Exh. AEB-16
Docket UG-240008
Witness: Ann E. Bulkley

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	DOCKET UG-240008

CASCADE NATURAL GAS CORPORATION

FIFTEENTH EXHIBIT TO THE
DIRECT TESTIMONY OF ANN E. BULKLEY

March 29, 2024

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Supreme Court of the United States
BLUEFIELD WATERWORKS & IMPROVEMENT CO.
v.
PUBLIC SERVICE COMMISSION OF WEST VIRGINIA et al.
No. 256.

Argued January 22, 1923.
Decided June 11, 1923.

In Error to the Supreme Court of Appeals of West Virginia.

Proceedings by the Bluefield Waterworks & Improvement Company against the Public Service Commission of the State of West Virginia and others to suspend and set aside an order of the Commission fixing rates. From a judgment of the Supreme Court of West Virginia, dismissing the petition, and denying the relief (89 W. Va. 736, 110 S. E. 205), the Waterworks Company bring error. Reversed.

West Headnotes

Constitutional Law 92 298(1.5)

92 Constitutional Law
92XII Due Process of Law
92k298 Regulation of Charges and Prices
92k298(1.5) k. Public Utilities in General. Most Cited Cases

Rates which are not sufficient to yield a reasonable return on the value of the property used in public service at the time it is being so used to render the service are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property, in violation of the Fourteenth Amendment of the Constitution.

Constitutional Law 92 298(3)

92 Constitutional Law
92XII Due Process of Law
92k298 Regulation of Charges and Prices
92k298(3) k. Water and Irrigation Companies. Most Cited Cases

Under the due process clause of the Fourteenth Amendment of the Constitution, U.S.C.A., a waterworks company is entitled to the independent judgment of the court as to both law and facts, where the question is whether the rates fixed by a public service commission are confiscatory.

Waters and Water Courses 405 203(10)

405 Waters and Water Courses
405IX Public Water Supply
405IX(A) Domestic and Municipal Purposes
405k203 Water Rents and Other Charges
405k203(10) k. Reasonableness of Charges. Most Cited Cases

It was error for a state public service commission, in arriving at the value of the property used in public service, for the purpose of fixing the rates, to fail to give proper weight to the greatly increased cost of construction since the war.

Waters and Water Courses 405 203(10)

405 Waters and Water Courses
405IX Public Water Supply
405IX(A) Domestic and Municipal Purposes
405k203 Water Rents and Other Charges
405k203(10) k. Reasonableness of Charges. Most Cited Cases

A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties, but it has no constitutional right to such profits as are realized or anticipated in highly profitable enterprises or speculative ventures.

Waters and Water Courses 405 203(10)

405 Waters and Water Courses
405IX Public Water Supply
405IX(A) Domestic and Municipal Purposes
405k203 Water Rents and Other Charges
405k203(10) k. Reasonableness

of Charges. Most Cited Cases
Since the investors take into account the result of past operations as well as present rates in determining whether they will invest, a waterworks company which had been earning a low rate of returns through a long period up to the time of the inquiry is entitled to return of more than 6 per cent. on the value of its property used in the public service, in order to justly compensate it for the use of its property.

Federal Courts 170B ⚷504.1

170B Federal Courts
170BVII Supreme Court
170BVII(E) Review of Decisions of State Courts
170Bk504 Nature of Decisions or Questions Involved
170Bk504.1 k. In General. Most Cited Cases
(Formerly 106k394(6))
A proceeding in a state court attacking an order of a public service commission fixing rates, on the ground that the rates were confiscatory and the order void under the federal Constitution, is one where there is drawn in question the validity of authority exercised under the state, on the ground of repugnancy to the federal Constitution, and therefore is reviewable by writ of error.

****675 *680** Messrs. Alfred G. Fox and Jos. M. Sanders, both of Bluefield, W. Va., for plaintiff in error.
Mr. Russell S. Ritz, of Bluefield, W. Va., for defendants in error.

***683** Mr. Justice BUTLER delivered the opinion of the Court.
Plaintiff in error is a corporation furnishing water to the city of Bluefield, W. Va., ****676** and its inhabitants. September 27, 1920, the Public Service Commission of the state, being authorized by statute to fix just and reasonable rates, made its order prescribing rates. In accordance with the laws of the state (section 16, c. 15-O, Code of West Virginia [sec. 651]), the company instituted proceedings in the Supreme Court of Appeals to suspend and set aside the order. The petition alleges that the order is repugnant to the Fourteenth Amendment, and deprives the company of its property without just compensation and without due process of law, and denies it equal protection of the laws. A final judgment was entered, denying the company relief and dismissing its petition. The case is here on writ of error.

[1] 1. The city moves to dismiss the writ of error for the reason, as it asserts, that there was not drawn in question the validity of a statute or an authority exercised under the state, on the ground of repugnancy to the federal Constitution.

The validity of the order prescribing the rates was directly challenged on constitutional grounds, and it was held valid by the highest court of the state. The prescribing of rates is a legislative act. The commission is an instrumentality of the state, exercising delegated powers. Its order is of the same force as would be a like enactment by the Legislature. If, as alleged, the prescribed rates are confiscatory, the order is void. Plaintiff in error is entitled to bring the case here on writ of error and to have that question decided by this court. The motion to dismiss will be denied. See ***684**Oklahoma Natural Gas Co. v. Russell, 261 U. S. 290, 43 Sup. Ct. 353, 67 L. Ed. 659, decided March 5, 1923, and cases cited; also Ohio Valley Co. v. Ben Avon Borough, 253 U. S. 287, 40 Sup. Ct. 527, 64 L. Ed. 908.

2. The commission fixed $460,000 as the amount on which the company is entitled to a return. It found that under existing rates, assuming some increase of business, gross earnings for 1921 would be $80,000 and operating expenses $53,000 leaving $27,000, the equivalent of 5.87 per cent., or 3.87 per cent. after deducting 2 per cent. allowed for depreciation. It held existing rates insufficient to the extent of 10,000. Its order allowed the company to add 16 per cent. to all bills, excepting those for public and private fire protection. The total of the bills so to be increased amounted to $64,000; that is, 80 per cent. of the revenue was authorized to be increased 16 per cent., equal to an increase of 12.8 per cent. on the total, amounting to $10,240.

As to value: The company claims that the value of the property is greatly in excess of $460,000. Reference to the evidence is necessary. There was submitted to the commission evidence of value which it summarized substantially as follows:

a. Estimate by company's engineer

(Cite as: P.U.R. 1923D 11, 43 S.Ct. 675)

	on. basis of reproduction new, less. depreciation, at prewar prices.	$ 624,548 00
b.	Estimate by company's engineer on. basis of reproduction new, less. depreciation, at 1920 prices.	1,194,663 00
c.	Testimony of company's engineer. fixing present fair value for rate. making purposes.	900,000 00
d.	Estimate by commissioner's engineer on. basis of reproduction new, less. depreciation at 1915 prices, plus. additions since December 31, 1915, at. actual cost, excluding Bluefield. Valley waterworks, water rights,. and going value.	397,964 38
e.	Report of commission's statistician. showing investment cost less. depreciation.	365,445 13
f.	Commission's valuation, as fixed in. case No. 368 ($360,000), plus gross. additions to capital since made. ($92,520.53).	452,520 53

***685** It was shown that the prices prevailing in 1920 were nearly double those in 1915 and pre-war time. The company did not claim value as high as its estimate of cost of construction in 1920. Its valuation engineer testified that in his opinion the value of the property was $900,000-a figure between the cost of construction in 1920, less depreciation, and the cost of construction in 1915 and before the war, less depreciation.

The commission's application of the evidence may be stated briefly as follows:

As to ‘a,’ supra: The commission deducted $204,000 from the estimate (details printed in the margin), FN1 leaving approximately $421,000, which it contrasted with the estimate of its own engineer, $397,964.38 (see ‘d,’ supra). It found that there should be included $25,000 for the Bluefield Valley waterworks plant in Virginia, 10 per cent. for going value, and $10,000 for working capital. If these be added to $421,000, there results $500,600. This may be compared with the commission's final figure, $460,000.

FN1

Difference in depreciation allowed.	$ 49,000
Preliminary organization and development. cost.	14,500
Bluefield Valley waterworks plant.	25,000
Water rights.	50,000
Excess overhead costs.	39,000
Paving over mains.	28,500
	$204,000

(Cite as: P.U.R. 1923D 11, 43 S.Ct. 675)

***686** As to 'b' and 'c,' supra: These were given no weight by the commission in arriving at its final figure, $460,000. It said:

'Applicant's plant was originally constructed more than twenty years ago, and has been added to from time to time as the progress and development of the community required. For this reason, it would be unfair to its consumers to use as a basis for present fair value the abnormal prices prevailing during the recent war period; but, when, as in this case, a part of the plant has been constructed or added to during that period, in fairness to the applicant, consideration must be given to the cost of such expenditures made to meet the demands of the public.'

****677** As to 'd,' supra: The commission, taking $400,000 (round figures), added $25,000 for Bluefield Valley waterworks plant in Virginia, 10 per cent. for going value, and $10,000 for working capital, making $477,500. This may be compared with its final figure, $460,000.

As to 'e,' supra: The commission, on the report of its statistician, found gross investment to be $500,402.53. Its engineer, applying the straight line method, found 19 per cent. depreciation. It applied 81 per cent. to gross investment and added 10 per cent. for going value and $10,000 for working capital, producing $455,500. FN2 This may be compared with its final figure, $460,000.

FN2 As to 'e': $365,445.13 represents investment cost less depreciation. The gross investment was found to be $500,402.53, indicating a deduction on account of depreciation of $134,957.40, about 27 per cent., as against 19 per cent. found by the commission's engineer.

As to 'f,' supra: It is necessary briefly to explain how this figure, $452,520.53, was arrived at. Case No. 368 was a proceeding initiated by the application of the company for higher rates, April 24, 1915. The commission made a valuation as of January 1, 1915. There were presented two estimates of reproduction cost less depreciation, one by a valuation engineer engaged by the company, ***687** and the other by a valuation engineer engaged by the city, both 'using the same method.' An inventory made by the company's engineer was accepted as correct by the city and by the commission. The method 'was that generally employed by courts and commissions in arriving at the value of public utility properties under this method.' and in both estimates 'five year average unit prices' were applied. The estimate of the company's engineer was $540,000 and of the city's engineer, $392,000. The principal differences as given by the commission are shown in the margin. FN3 The commission disregarded both estimates and arrived at $360,000. It held that the best basis of valuation was the net investment, i. e., the total cost of the property less depreciation. It said:

FN3

		Company Engineer.	City Engineer.
1.	Preliminary costs.	$14,455	$1,000
2.	Water rights.	50,000	Nothing
3.	Cutting pavements over mains.	27,744	233
4.	Pipe lines from gravity springs.	22,072	15,442
5.	Laying cast iron street mains.	19,252	15,212
6.	Reproducing Ada springs.	18,558	13,027
7.	Superintendence and engineering.	20,515	13,621
8.	General contingent cost.	16,415	5,448
		$189,011	$63,983

'The books of the company show a total gross investment, since its organization, of $407,882, and that there has been charged off for depreciation from year to year the total sum of $83,445, leaving a net investment of

(Cite as: P.U.R. 1923D 11, 43 S.Ct. 675)

$324,427. * * * From an examination of the books * * * it appears that the records of the company have been remarkably well kept and preserved. It therefore seems that, when a plant is developed under these conditions, the net investment, which, of course, means the total gross investment less depreciation, is the very best basis of valuation for rate making purposes and that the other methods above referred to should ***688** be used only when it is impossible to arrive at the true investment. Therefore, after making due allowance for capital necessary for the conduct of the business and considering the plant as a going concern, it is the opinion of the commission that the fair value for the purpose of determining reasonable and just rates in this case of the property of the applicant company, used by it in the public service of supplying water to the city of Bluefield and its citizens, is the sum of $360,000, which sum is hereby fixed and determined by the commission to be the fair present value for the said purpose of determining the reasonable and just rates in this case.'

In its report in No. 368, the commission did not indicate the amounts respectively allowed for going value or working capital. If 10 per cent. be added for the former, and $10,000 for the latter (as fixed by the commission in the present case), there is produced $366,870, to be compared with $360,000, found by the commission in its valuation as of January 1, 1915. To this it added $92,520.53, expended since, producing $452,520.53. This may be compared with its final figure, $460,000.

The state Supreme Court of Appeals holds that the valuing of the property of a public utility corporation and prescribing rates are purely legislative acts, not subject to judicial review, except in so far as may be necessary to determine whether such rates are void on constitutional or other grounds, and that findings of fact by the commission based on evidence to support them will not be reviewed by the court. City of Bluefield v. Waterworks, 81 W. Va. 201, 204, 94 S. E. 121; Coal & Coke Co. v. Public Service Commission, 84 W. Va. 662, 678, 100 S. E. 557, 7 A. L. R. 108; Charleston v. Public Service Commission, 86 W. Va. 536, 103 S. E. 673.

In this case (89 W. Va. 736, 738, 110 S. E. 205, 206) it said:
'From the written opinion of the commission we find that it ascertained the value of the petitioner's property for rate making [then quoting the commission] 'after ***689** maturely and carefully considering the various methods presented for the ascertainment of fair value and giving such weight as seems proper to every element involved and all the facts and circumstances disclosed by the record.''

[2] [3] The record clearly shows that the commission, in arriving at its final figure, did not accord proper, if any, weight to the greatly enhanced costs of construction in 1920 over those prevailing about 1915 and before the war, as established by uncontradicted ****678** evidence; and the company's detailed estimated cost of reproduction new, less depreciation, at 1920 prices, appears to have been wholly disregarded. This was erroneous. Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, 262 U. S. 276, 43 Sup. Ct. 544, 67 L. Ed. 981, decided May 21, 1923. Plaintiff in error is entitled under the due process clause of the Fourteenth Amendment to the independent judgment of the court as to both law and facts. Ohio Valley Co. v. Ben Avon Borough, 253 U. S. 287, 289, 40 Sup. Ct. 527, 64 L. Ed. 908, and cases cited.

We quote further from the court's opinion (89 W. Va. 739, 740, 110 S. E. 206):
'In our opinion the commission was justified by the law and by the facts in finding as a basis for rate making the sum of $460,000.00. * * * In our case of Coal & Coke Ry. Co. v. Conley, 67 W. Va. 129, it is said: 'It seems to be generally held that, in the absence of peculiar and extraordinary conditions, such as a more costly plant than the public service of the community requires, or the erection of a plant at an actual, though extravagant, cost, or the purchase of one at an exorbitant or inflated price, the actual amount of money invested is to be taken as the basis, and upon this a return must be allowed equivalent to that which is ordinarily received in the locality in which the business is done, upon capital invested in similar enterprises. In addition to this, consideration must be given to the nature of the investment, a higher rate ***690** being regarded as justified by the risk incident to a hazardous investment.'
'That the original cost considered in connection with the history and growth of the utility and the value of the services rendered constitute the principal elements to be considered in connection with rate making, seems to be supported by nearly all the authorities.'

[4] The question in the case is whether the rates prescribed in the commission's order are confiscatory and therefore beyond legislative power. Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment. This is so well settled by numerous decisions of this court that citation of the cases is scarcely necessary:

(Cite as: P.U.R. 1923D 11, 43 S.Ct. 675)

'What the company is entitled to ask is a fair return upon the value of that which it employs for the public convenience.' Smyth v. Ames (1898) 169 U. S. 467, 547, 18 Sup. Ct. 418, 434 (42 L. Ed. 819).
'There must be a fair return upon the reasonable value of the property at the time it is being used for the public. * * * And we concur with the court below in holding that the value of the property is to be determined as of the time when the inquiry is made regarding the rates. If the property, which legally enters into the consideration of the question of rates, has increased in value since it was acquired, the company is entitled to the benefit of such increase.' Willcox v. Consolidated Gas Co. (1909) 212 U. S. 19, 41, 52, 29 Sup. Ct. 192, 200 (53 L. Ed. 382, 15 Ann. Cas. 1034, 48 L. R. A. [N. S.] 1134).
'The ascertainment of that value is not controlled by artificial rules. It is not a matter of formulas, but there must be a reasonable judgment having its basis in a proper consideration of all relevant facts.' Minnesota Rate Cases (1913) 230 U. S. 352, 434, 33 Sup. Ct. 729, 754 (57 L. Ed. 1511, 48 L. R. A. [N. S.] 1151, Ann. Cas. 1916A, 18).
***691** 'And in order to ascertain that value, the original cost of construction, the amount expended in permanent improvements, the amount and market value of its bonds and stock, the present as compared with the original cost of construction, the probable earning capacity of the property under particular rates prescribed by statute, and the sum required to meet operating expenses, are all matters for consideration, and are to be given such weight as may be just and right in each case. We do not say that there may not be other matters to be regarded in estimating the value of the property.' Smyth v. Ames, 169 U. S., 546, 547, 18 Sup. Ct. 434, 42 L. Ed. 819.
'* * * The making of a just return for the use of the property involves the recognition of its fair value if it be more than its cost. The property is held in private ownership and it is that property, and not the original cost of it, of which the owner may not be deprived without due process of law.'

Minnesota Rate Cases, 230 U. S. 454, 33 Sup. Ct. 762, 57 L. Ed. 1511, 48 L. R. A. (N. S.) 1151, Ann. Cas. 1916A, 18.

In Missouri ex rel. Southwestern Bell Telephone Co., v. Public Service Commission of Missouri, supra, applying the principles of the cases above cited and others, this court said:
'Obviously, the commission undertook to value the property without according any weight to the greatly enhanced costs of material, labor, supplies, etc., over those prevailing in 1913, 1914, and 1916. As matter of common knowledge, these increases were large. Competent witnesses estimated them as 45 to 50 per centum. * * * It is impossible to ascertain what will amount to a fair return upon properties devoted to public service, without giving consideration to the cost of labor, supplies, etc., at the time the investigation is made. An honest and intelligent forecast of probable future values, made upon a view of all the relevant circumstances, is essential. If the highly important element of present costs is wholly disregarded, such a forecast becomes impossible. Estimates for to-morrow cannot ignore prices of to-day.'

[5] ***692** It is clear that the court also failed to give proper consideration to the higher cost of construction in 1920 over that in 1915 and before the war, and failed to give weight to cost of reproduction less depreciation on the basis of 1920 prices, or to the testimony of the company's valuation engineer, based on present and past costs of construction, that the property in his opinion, was worth $900,000. The final figure, $460,000, was arrived ****679** at substantially on the basis of actual cost, less depreciation, plus 10 per cent. for going value and $10,000 for working capital. This resulted in a valuation considerably and materially less than would have been reached by a fair and just consideration of all the facts. The valuation cannot be sustained. Other objections to the valuation need not be considered.

3. Rate of return: The state commission found that the company's net annual income should be approximately $37,000, in order to enable it to earn 8 per cent. for return and depreciation upon the value of its property as fixed by it. Deducting 2 per cent. for depreciation, there remains 6 per cent. on $460,000, amounting to $27,600 for return. This was approved by the state court.

[6] The company contends that the rate of return is too low and confiscatory. What annual rate will constitute just compensation depeds upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in ***693** highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A

rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

In 1909, this court, in Willcox v. Consolidated Gas Co., 212 U. S. 19, 48-50, 29 Sup. Ct. 192, 53 L. Ed. 382, 15 Ann. Cas. 1034, 48 L. R. A. (N. S.) 1134, held that the question whether a rate yields such a return as not to be confiscatory depends upon circumstances, locality and risk, and that no proper rate can be established for all cases; and that, under the circumstances of that case, 6 per cent. was a fair return on the value of the property employed in supplying gas to the city of New York, and that a rate yielding that return was not confiscatory. In that case the investment was held to be safe, returns certain and risk reduced almost to a minimum-as nearly a safe and secure investment as could be imagined in regard to any private manufacturing enterprise.

In 1912, in Cedar Rapids Gas Co. v. Cedar Rapids, 223 U. S. 655, 670, 32 Sup. Ct. 389, 56 L. Ed. 594, this court declined to reverse the state court where the value of the plant considerably exceeded its cost, and the estimated return was over 6 per cent.

In 1915, in Des Moines Gas Co. v. Des Moines, 238 U. S. 153, 172, 35 Sup. Ct. 811, 59 L. Ed. 1244, this court declined to reverse the United States District Court in refusing an injunction upon the conclusion reached that a return of 6 per cent. per annum upon the value would not be confiscatory.

In 1919, this court in Lincoln Gas Co. v. Lincoln, 250 U. S. 256, 268, 39 Sup. Ct. 454, 458 (63 L. Ed. 968), declined on the facts of that case to approve a finding that no rate yielding as much as 6 per cent. ***694** on the invested capital could be regarded as confiscatory. Speaking for the court, Mr. Justice Pitney said:
'It is a matter of common knowledge that, owing principally to the World War, the costs of labor and supplies of every kind have greatly advanced since the ordinance was adopted, and largely since this cause was last heard in the court below. And it is equally well known that annual returns upon capital and enterprise the world over have materially increased, so that what would have been a proper rate of return for capital invested in gas plants and similar public utilities a few years ago furnishes no safe criterion for the present or for the future.'

In 1921, in Brush Electric Co. v. Galveston, the United States District Court held 8 per cent. a fair rate of return. [FN4]

FN4 This case was affirmed by this court June 4, 1923, 262 U. S. 443, 43 Sup. Ct. 606, 67 L. Ed. 1076.

In January, 1923, in City of Minneapolis v. Rand, the Circuit Court of Appeals of the Eighth Circuit (285 Fed. 818, 830) sustained, as against the attack of the city on the ground that it was excessive, 7 1/2 per cent., found by a special master and approved by the District Court as a fair and reasonable return on the capital investment-the value of the property.

[7] Investors take into account the result of past operations, especially in recent years, when determining the terms upon which they will invest in such an undertaking. Low, uncertain, or irregular income makes for low prices for the securities of the utility and higher rates of interest to be demanded by investors. The fact that the company may not insist as a matter of constitutional right that past losses be made up by rates to be applied in the present and future tends to weaken credit, and the fact that the utility is protected against being compelled to serve for confiscatory rates tends to support it. In ***695** this case the record shows that the rate of return has been low through a long period up to the time of the inquiry by the commission here involved. For example, the average rate of return on the total cost of the property from 1895 to 1915, inclusive, was less than 5 per cent.; from 1911 to 1915, inclusive, about 4.4 per cent., without allowance for depreciation. In 1919 the net operating income was approximately $24,700, leaving $15,500, approximately, or 3.4 per cent. on $460,000 fixed by the commission, after deducting 2 per cent. for depreciation. In 1920, the net operating income was approximately $25,465, leaving $16,265 for return, after allowing for depreciation. Under the facts and circumstances indicated by the record, we think that a rate of return of 6 per cent. upon the value of the property is substantially too low to constitute just compensation for the use of the property employed to render the service.

The judgment of the Supreme Court of Appeals of West Virginia is reversed.

Mr. Justice BRANDEIS concurs in the judgment of reversal, for the reasons stated by him in Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, supra.
U.S. 1923
Bluefield Waterworks & Imp. Co. v. Public Service Commission of W. Va.
P.U.R. 1923D 11, 262 U.S. 679, 43 S.Ct. 675, 67 L.Ed. 1176

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Supreme Court of the United States
FEDERAL POWER COMMISSION et al.
v.
HOPE NATURAL GAS CO.
CITY OF CLEVELAND
v.
SAME.
Nos. 34 and 35.

Argued Oct. 20, 21, 1943.
Decided Jan. 3, 1944.

Separate proceedings before the Federal Power Commission by such Commission, by the City of Cleveland and the City of Akron, and by Pennsylvania Public Utility Commission wherein the State of West Virginia and its Public Service Commission were permitted to intervene concerning rates charged by Hope Natural Gas Company which were consolidated for hearing. An order fixing rates was reversed and remanded with directions by the Circuit Court of Appeals, 134 F.2d 287, and Federal Power Commission, City of Akron and Pennsylvania Public Utility Commission in one case and the City of Cleveland in another bring certiorari.

Reversed.

Mr. Justice REED, Mr. Justice FRANKFURTER and Mr. Justice JACKSON, dissenting.

On Writs of Certiorari to the United States Circuit Court of Appeals for the Fourth Circuit.

West Headnotes

[1] **Public Utilities 317A 120**

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges
317Ak120 k. Nature and Extent in General. Most Cited Cases
(Formerly 317Ak7.1, 317Ak7)
Rate-making is only one species of price-fixing which, like other applications of the police power, may reduce the value of the property regulated, but that does not render the regulation invalid.

[2] **Public Utilities 317A 123**

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges
317Ak123 k. Reasonableness of Charges in General. Most Cited Cases
(Formerly 317Ak7.4, 317Ak7)
Rates cannot be made to depend upon fair value, which is the end product of the process of rate-making and not the starting point, when the value of the going enterprise depends on earnings under whatever rates may be anticipated.

[3] **Gas 190 14.3(2)**

190 Gas
190k14 Charges
190k14.3 Administrative Regulation
190k14.3(2) k. Federal Power Commission. Most Cited Cases
(Formerly 190k14(1))
The rate-making function of the Federal Power Commission under the Natural Gas Act involves the making of pragmatic adjustments, and the Commission is not bound to the use of any single formula or combination of formulae in determining rates. Natural Gas Act, § § 4(a), 5(a), 6, 15 U.S.C.A. § § 717c(a), 717d(a), 717e.

[4] **Gas 190 14.5(6)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(6) k. Scope of Review and Trial De Novo. Most Cited Cases
(Formerly 190k14(1))
When order of Federal Power Commission fixing natural gas rates is challenged in the courts, the question is whether order viewed in its entirety meets the requirements of the Natural Gas Act. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[5] **Gas 190 14.4(1)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges

190k14.4(1) k. In General. Most Cited Cases
(Formerly 190k14(1))
Under the statutory standard that natural gas rates shall be "just and reasonable" it is the result reached and not the method employed that is controlling. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[6] **Gas 190 ⚷14.5(6)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(6) k. Scope of Review and Trial De Novo. Most Cited Cases
(Formerly 190k14(1))
If the total effect of natural gas rates fixed by Federal Power Commission cannot be said to be unjust and unreasonable, judicial inquiry under the Natural Gas Act is at an end. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[7] **Gas 190 ⚷14.5(7)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(7) k. Presumptions. Most Cited Cases
(Formerly 190k14(1))
An order of the Federal Power Commission fixing rates for natural gas is the product of expert judgment, which carries a presumption of validity, and one who would upset the rate must make a convincing showing that it is invalid because it is unjust and unreasonable in its consequences. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[8] **Gas 190 ⚷14.4(1)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(1) k. In General. Most Cited Cases
(Formerly 190k14(1))
The fixing of just and reasonable rates for natural gas by the Federal Power Commission involves a balancing of the investor and the consumer interests. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[9] **Gas 190 ⚷14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
As respects rates for natural gas, from the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business, which includes service on the debt and dividends on stock, and by such standard the return to the equity owner should be commensurate with the terms on investments in other enterprises having corresponding risks, and such returns should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[10] **Gas 190 ⚷14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
The fixing by the Federal Power Commission of a rate of return that permitted a natural gas company to earn $2,191,314 annually was supported by substantial evidence. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[11] **Gas 190 ⚷14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
Rates which enable a natural gas company to operate successfully, to maintain its financial integrity, to attract capital and to compensate its investors for the risks assumed cannot be condemned as invalid, even though they might produce only a meager return on the so-called "fair value" rate base. Natural Gas Act,

§ § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[12] **Gas 190 14.4(4)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(4) k. Method of Valuation. Most Cited Cases
(Formerly 190k14(1))
A return of only 3 27/100 per cent. on alleged rate base computed on reproduction cost new to natural gas company earning an annual average return of about 9 per cent. on average investment and satisfied with existing gas rates suggests an inflation of the base on which the rate had been computed, and justified Federal Power Commission in rejecting reproduction cost as the measure of the rate base. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[13] **Gas 190 14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
There is no constitutional requirement that owner who engages in a wasting-asset business of limited life shall receive at the end more than he has put into it, and such rule is applicable to a natural gas company since the ultimate exhaustion of its supply of gas is inevitable. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[14] **Gas 190 14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
In fixing natural gas rate the basing of annual depreciation on cost is proper since by such procedure the utility is made whole and the integrity of its investment is maintained, and no more is required. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[15] **Gas 190 14.3(4)**

190 Gas
190k14 Charges
190k14.3 Administrative Regulation
190k14.3(4) k. Findings and Orders. Most Cited Cases
(Formerly 190k14(1))
There are no constitutional requirements more exacting than the standards of the Natural Gas Act which are that gas rates shall be just and reasonable, and a rate order which conforms with the act is valid. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[16] **Commerce 83 62.2**

83 Commerce
83II Application to Particular Subjects and Methods of Regulation
83II(B) Conduct of Business in General
83k62.2 k. Gas. Most Cited Cases
(Formerly 83k13)
The purpose of the Natural Gas Act was to provide through the exercise of the national power over interstate commerce an agency for regulating the wholesale distribution to public service companies of natural gas moving in interstate commerce not subject to certain types of state regulation, and the act was not intended to take any authority from state commissions or to usurp state regulatory authority. Natural Gas Act, § 1 et seq., 15 U.S.C.A. § 717 et seq.

[17] **Mines and Minerals 260 92.5(3)**

260 Mines and Minerals
260III Operation of Mines, Quarries, and Wells
260III(A) Statutory and Official Regulations
260k92.5 Federal Law and Regulations
260k92.5(3) k. Oil and Gas. Most Cited Cases
(Formerly 260k92.7, 260k92)
Under the Natural Gas Act, the Federal Power Commission has no authority over the production or gathering of natural gas. Natural Gas Act, § 1(b), 15 U.S.C.A. § 717(b).

[18] **Gas 190 14.1(1)**

190 Gas
190k14 Charges
190k14.1 In General
190k14.1(1) k. In General; Amount and

Regulation. Most Cited Cases
(Formerly 190k14(1))
The primary aim of the Natural Gas Act was to protect consumers against exploitation at the hands of natural gas companies and holding companies owning a majority of the pipe-line mileage which moved gas in interstate commerce and against which state commissions, independent producers and communities were growing quite helpless. Natural Gas Act, § § 4, 6-10, 14, 15 U.S.C.A. § § 717c, 717e-717i, 717m.

[19] **Gas 190 14.1(1)**

190 Gas
190k14 Charges
190k14.1 In General
190k14.1(1) k. In General; Amount and Regulation. Most Cited Cases
(Formerly 190k14(1))
Apart from the express exemptions contained in § 7 of the Natural Gas Act considerations of conservation are material where abandonment or extensions of facilities or service by natural gas companies are involved, but exploitation of consumers by private operators through maintenance of high rates cannot be continued because of the indirect benefits derived therefrom by a state containing natural gas deposits. Natural Gas Act, § § 4, 5, and § 7 as amended 15 U.S.C.A. § § 717c, 717d, 717f.

[20] **Commerce 83 62.2**

83 Commerce
83II Application to Particular Subjects and Methods of Regulation
83II(B) Conduct of Business in General
83k62.2 k. Gas. Most Cited Cases
(Formerly 83k13)
A limitation on the net earnings of a natural gas company from its interstate business is not a limitation on the power of the producing state, either to safeguard its tax revenues from such industry, or to protect the interests of those who sell their gas to the interstate operator, particularly where the return allowed the company by the Federal Power Commission was a net return after all such charges. Natural Gas Act, § § 4, 5, and § 7, as amended, 15 U.S.C.A. § § 717c, 717d, 717f.

[21] **Gas 190 14.4(1)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(1) k. In General. Most Cited Cases
(Formerly 190k14(1))
The Natural Gas Act granting Federal Power Commission power to fix "just and reasonable rates" does not include the power to fix rates which will disallow or discourage resales for industrial use. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[22] **Gas 190 14.4(1)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(1) k. In General. Most Cited Cases
(Formerly 190k14(1))
The wasting-asset nature of the natural gas industry does not require the maintenance of the level of rates so that natural gas companies can make a greater profit on each unit of gas sold. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[23] **Federal Courts 170B 452**

170B Federal Courts
170BVII Supreme Court
170BVII(B) Review of Decisions of Courts of Appeals
170Bk452 k. Certiorari in General. Most Cited Cases
(Formerly 106k383(1))
Where the Federal Power Commission made no findings as to any discrimination or unreasonable differences in rates, and its failure was not challenged in the petition to review, and had not been raised or argued by any party, the problem of discrimination was not open to review by the Supreme Court on certiorari. Natural Gas Act, § 4(b), 15 U.S.C.A. § 717c(b).

[24] **Constitutional Law 92 74**

92 Constitutional Law
92III Distribution of Governmental Powers and Functions
92III(B) Judicial Powers and Functions
92k71 Encroachment on Executive
92k74 k. Powers, Duties, and Acts Under Legislative Authority. Most Cited Cases
(Formerly 15Ak226)
Congress has entrusted the administration of the

Natural Gas Act to the Federal Power Commission and not to the courts, and apart from the requirements of judicial review, it is not for the Supreme Court to advise the Commission how to discharge its functions. Natural Gas Act, § § 1 et seq., 19(b), 15 U.S.C.A. § § 717 et seq., 717r(b).

[25] **Gas 190 ⚷14.5(3)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(3) k. Decisions Reviewable. Most Cited Cases
(Formerly 190k14(1))

Under the Natural Gas Act, where order sought to be reviewed does not of itself adversely affect complainant but only affects his rights adversely on the contingency of future administrative action, the order is not reviewable, and resort to the courts in such situation is either premature or wholly beyond the province of such courts. Natural Gas Act, § 19(b), 15 U.S.C.A. § 717r(b).

[26] **Gas 190 ⚷14.5(4)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(4) k. Persons Entitled to Relief; Parties. Most Cited Cases
(Formerly 190k14(1))

Findings of the Federal Power Commission on lawfulness of past natural gas rates, which the Commission was without power to enforce, were not reviewable under the Natural Gas Act giving any "party aggrieved" by an order of the Commission the right of review. Natural Gas Act, § 19(b), 15 U.S.C.A. § 717r(b).

****283 *592** Mr. Francis M. Shea, Asst. Atty. Gen., for petitioners Federal Power Com'n and others.
***593** Mr. Spencer W. Reeder, of Cleveland, Ohio, for petitioner City of cleveland.
Mr. William B. Cockley, of Cleveland, Ohio, for respondent.
Mr. M. M. Neeley, of Charleston, W. Va., for State of West Virginia, as amicus curiae by special leave of Court.

Mr. Justice DOUGLAS delivered the opinion of the Court.

The primary issue in these cases concerns the validity under the Natural Gas Act of 1938, 52 Stat. 821, 15 U.S.C. s 717 et seq., 15 U.S.C.A. s 717 et seq., of a rate order issued by the Federal Power Commission reducing the rates chargeable by Hope Natural Gas Co., 44 P.U.R.,N.S., 1. On a petition for review of the order made pursuant to s 19(b) of the Act, the ***594** Circuit Court of Appeals set it aside, one judge dissenting. 4 Cir., 134 F.2d 287. The cases ****284** are here on petitions for writs of certiorari which we granted because of the public importance of the questions presented. City of Cleveland v. Hope Natural Gas Co., 319 U.S. 735, 63 S.Ct. 1165.

Hope is a West Virginia corporation organized in 1898. It is a wholly owned subsidiary of Standard Oil Co. (N.J.). Since the date of its organization, it has been in the business of producing, purchasing and marketing natural gas in that state. [FN1] It sells some of that gas to local consumers in West Virginia. But the great bulk of it goes to five customer companies which receive it at the West Virginia line and distribute it in Ohio and in Pennsylvania. [FN2] In July, 1938, the cities of Cleveland and Akron filed complaints with the Commission charging that the rates collected by Hope from East Ohio Gas Co. (an affiliate of Hope which distributes gas in Ohio) were excessive and unreasonable. Later in 1938 the Commission on its own motion instituted an investigation to determine the reasonableness of all of Hope's interstate rates. In March ***595** 1939 the Public Utility Commission of Pennsylvania filed a complaint with the Commission charging that the rates collected by Hope from Peoples Natural Gas Co. (an affiliate of Hope distributing gas in Pennsylvania) and two non-affiliated companies were unreasonable. The City of Cleveland asked that the challenged rates be declared unlawful and that just and reasonable rates be determined from June 30, 1939 to the date of the Commission's order. The latter finding was requested in aid of state regulation and to afford the Public Utilities Commission of Ohio a proper basic for disposition of a fund collected by East Ohio under bond from Ohio consumers since June 30, 1939. The cases were consolidated and hearings were held.

FN1 Hope produces about one-third of its annual gas requirements and purchases the rest under some 300 contracts.

FN2 These five companies are the East Ohio Gas Co., the Peoples Natural Gas Co., the

River Gas Co., the Fayette County Gas Co., and the Manufacturers Light & Heat Co. The first three of these companies are, like Hope, subsidiaries of Standard Oil Co. (N.J.). East Ohio and River distribute gas in Ohio, the other three in Pennsylvania. Hope's approximate sales in m.c.f. for 1940 may be classified as follows:

Local West Virginia. sales.	11,000,000
East Ohio.	40,000,000
Peoples.	10,000,000
River.	400,000
Fayette.	860,000
Manufacturers.	2,000,000

Local West Virginia

Hope's natural gas is processed by Hope Construction & Refining Co., an affiliate, for the extraction of gasoline and butane. Domestic Coke Corp., another affiliate, sells coke-oven gas to Hope for boiler fuel.

On May 26, 1942, the Commission entered its order and made its findings. Its order required Hope to decrease its future interstate rates so as to reflect a reduction, on an annual basis of not less than $3,609,857 in operating revenues. And it established 'just and reasonable' average rates per m.c.f. for each of the five customer companies. FN3 In response to the prayer of the City of Cleveland the Commission also made findings as to the lawfulness of past rates, although concededly it had no authority under the Act to fix past rates or to award reparations. 44 P.U.R.,U.S., at page 34. It found that the rates collected by Hope from East Ohio were unjust, unreasonable, excessive and therefore unlawful, by $830,892 during 1939, $3,219,551 during 1940, and $2,815,789 on an annual basis since 1940. It further found that just, reasonable, and lawful rates for gas sold by Hope to East Ohio for resale for ultimate public consumption were those required ***596** to produce $11,528,608 for 1939, $11,507,185 for 1940 and $11.910,947 annually since 1940.

FN3 These required minimum reductions of 7¢ per m.c.f. from the 36.5¢ and 35.5¢ rates previously charged East Ohio and Peoples, respectively, and 3¢ per m.c.f. from the 31.5¢ rate previously charged Fayette and Manufacturers.

The Commission established an interstate rate base of $33,712,526 which, it found, represented the 'actual legitimate cost' of the company's interstate property less depletion and depreciation and plus unoperated acreage, working capital and future net capital additions. The Commission, beginning with book cost, made ****285** certain adjustments not necessary to relate here and found the 'actual legitimate cost' of the plant in interstate service to be $51,957,416, as of December 31, 1940. It deducted accrued depletion and depreciation, which it found to be $22,328,016 on an 'economic-service-life' basis. And it added $1,392,021 for future net capital additions, $566,105 for useful unoperated acreage, and $2,125,000 for working capital. It used 1940 as a test year to estimate future revenues and expenses. It allowed over $16,000,000 as annual operating expenses-about $1,300,000 for taxes, $1,460,000 for depletion and depreciation, $600,000 for exploration and development costs, $8,500,000 for gas purchased. The Commission allowed a net increase of $421,160 over 1940 operating expenses, which amount was to take care of future increase in wages, in West Virginia property taxes, and in exploration and development costs. The total amount of deductions allowed from interstate revenues was $13,495,584.

Hope introduced evidence from which it estimated reproduction cost of the property at $97,000,000. It also presented a so-called trended 'original cost' estimate which exceeded $105,000,000. The latter was designed 'to indicate what the original cost of the property would have been if 1938 material and labor prices had prevailed throughout the whole period of the piece-meal construction of the company's property since 1898.' 44 P.U.R.,N.S., at pages 8, 9. Hope estimated by the 'percent condition' method accrued depreciation at about 35% of ***597** reproduction cost new. On that basis Hope contended for a rate base of $66,000,000. The Commission refused to place any reliance on reproduction cost new, saying that it was 'not predicated upon facts' and was 'too conjectural and illusory to be given any weight in these proceedings.' Id., 44 P.U.R.,U.S., at page 8. It likewise refused to give any 'probative value' to trended 'original cost' since it was 'not founded in fact' but was 'basically erroneous' and produced 'irrational results.' Id., 44 P.U.R., N.S., at page 9. In determining the amount of accrued depletion and depreciation the Commission, following Lindheimer v. Illinois Bell

Telephone Co., 292 U.S. 151, 167-169, 54 S.Ct. 658, 664-666, 78 L.Ed. 1182; Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 592, 593, 62 S.Ct. 736, 745, 746, 86 L.Ed. 1037, based its computation on 'actual legitimate cost'. It found that Hope during the years when its business was not under regulation did not observe 'sound depreciation and depletion practices' but 'actually accumulated an excessive reserve' FN4 of about $46,000,000. Id., 44 P.U.R.,N.S., at page 18. One member of the Commission thought that the entire amount of the reserve should be deducted from 'actual legitimate cost' in determining the rate base. FN5 The majority of the ***598** Commission concluded, however, that where, as here, a business is brought under regulation for the first time and where incorrect depreciation and depletion practices have prevailed, the deduction of the reserve requirement (actual existing depreciation and depletion) rather than the excessive reserve should be made so as to ****286** lay 'a sound basis for future regulation and control of rates.' Id., 44 P.U.R.,N.S., at page 18. As we have pointed out, it determined accrued depletion and depreciation to be $22,328,016; and it allowed approximately $1,460,000 as the annual operating expense for depletion and depreciation. FN6

FN4 The book reserve for interstate plant amounted at the end of 1938 to about $18,000,000 more than the amount determined by the Commission as the proper reserve requirement. The Commission also noted that 'twice in the past the company has transferred amounts aggregating $7,500,000 from the depreciation and depletion reserve to surplus. When these latter adjustments are taken into account, the excess becomes $25,500,000, which has been exacted from the ratepayers over and above the amount required to cover the consumption of property in the service rendered and thus to keep the investment unimpaired.' 44 P.U.R.,N.S., at page 22.

FN5 That contention was based on the fact that 'every single dollar in the depreciation and depletion reserves' was taken 'from gross operating revenues whose only source was the amounts charged customers in the past for natural gas. It is, therefore, a fact that the depreciation and depletion reserves have been contributed by the customers and do not represent any investment by Hope.' Id., 44 P.U.R.,N.S., at page 40. And see Railroad Commission v. Cumberland Tel. & T. Co., 212 U.S. 414, 424, 425, 29 S.Ct. 357, 361, 362, 53 L.Ed. 577; 2 Bonbright, Valuation of Property (1937), p. 1139.

FN6 The Commission noted that the case was 'free from the usual complexities involved in the estimate of gas reserves because the geologists for the company and the Commission presented estimates of the remaining recoverable gas reserves which were about one per cent apart.' 44 P.U.R.,N.S., at pages 19, 20.

The Commission utilized the 'straight-line-basis' for determining the depreciation and depletion reserve requirements. It used estimates of the average service lives of the property by classes based in part on an inspection of the physical condition of the property. And studies were made of Hope's retirement experience and maintenance policies over the years. The average service lives of the various classes of property were converted into depreciation rates and then applied to the cost of the property to ascertain the portion of the cost which had expired in rendering the service.

The record in the present case shows that Hope is on the lookout for new sources of supply of natural gas and is contemplating an extension of its pipe line into Louisiana for that purpose. The Commission recognized in fixing the rates of depreciation that much material may be used again when various present sources of gas supply are exhausted, thus giving that property more than scrap value at the end of its present use.

Hope's estimate of original cost was about $69,735,000-approximately $17,000,000 more than the amount found by the Commission. The item of $17,000,000 was made up largely of expenditures which prior to December 31, 1938, were charged to operating expenses. Chief among those expenditures was some $12,600,000 expended ***599** in well-drilling prior to 1923. Most of that sum was expended by Hope for labor, use of drilling-rigs, hauling, and similar costs of well-drilling. Prior to 1923 Hope followed the general practice of the natural gas industry and charged the cost of drilling wells to operating expenses. Hope continued that practice until the Public Service Commission of West Virginia in 1923 required it to capitalize such expenditures, as does the Commission under its present Uniform System of Accounts. FN7 The Commission refused to add such items to the rate base stating that 'No greater injustice to consumers could be done than to allow items as operating expenses and at a later date include them in the rate base, thereby placing multiple charges upon the consumers.' Id., 44 P.U.R.,N.S., at page 12. For the same reason the Commission excluded from the rate base about $1,600,000 of expenditures on properties which Hope acquired from other utilities, the latter having charged those payments to operating expenses. The Commission disallowed certain other overhead items amounting to over $3,000,000 which also had been previously charged to operating expenses. And it refused to add some $632,000 as interest during construction since no interest was in fact paid.

FN7 See Uniform System of Accounts prescribed for Natural Gas Companies effective January 1, 1940, Account No. 332.1.

Hope contended that it should be allowed a return of not less than 8%. The Commission found that an 8% return would be unreasonable but that 6 1/2% was a fair rate of return. That rate of return, applied to the rate base of $33,712,526, would produce $2,191,314 annually, as compared with the present income of not less than $5,801,171.

The Circuit Court of Appeals set aside the order of the Commission for the following reasons. (1) It held that the rate base should reflect the 'present fair value' of the ***600** property, that the Commission in determining the 'value' should have considered reproduction cost and trended original cost, and that 'actual legitimate cost' (prudent investment) was not the proper measure of 'fair value' where price levels had changed since the investment. (2) It concluded that the well-drilling costs and overhead items in the amount of some $17,000,000 should have been included in the rate base. (3) It held that accrued depletion and depreciation and the annual allowance for that expense should be computed on the basis of 'present fair value' of the property not on the basis of 'actual legitimate cost'.

****287** The Circuit Court of Appeals also held that the Commission had no power to make findings as to past rates in aid of state regulation. But it concluded that those findings were proper as a step in the process of fixing future rates. Viewed in that light, however, the findings were deemed to be invalidated by the same errors which vitiated the findings on which the rate order was based.

Order Reducing Rates. Congress has provided in s 4(a) of the Natural Gas Act that all natural gas rates subject to the jurisdiction of the Commission 'shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.' Sec. 5(a) gives the Commission the power, after hearing, to determine the 'just and reasonable rate' to be thereafter observed and to fix the rate by order. Sec. 5(a) also empowers the Commission to order a 'decrease where existing rates are unjust * * * unlawful, or are not the lowest reasonable rates.' And Congress has provided in s 19(b) that on review of these rate orders the 'finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive.' Congress, however, has provided no formula by which the 'just and reasonable' rate is to be determined. It has not filled in the ***601** details of the general prescription [FN8] of s 4(a) and s 5(a). It has not expressed in a specific rule the fixed principle of 'just and reasonable'.

FN8. Sec. 6 of the Act comes the closest to supplying any definite criteria for rate making. It provides in subsection (a) that, 'The Commission may investigate the ascertain the actual legitimate cost of the property of every natural-gas company, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation and the fair value of such property.' Subsection (b) provides that every natural-gas company on request shall file with the Commission a statement of the 'original cost' of its property and shall keep the Commission informed regarding the 'cost' of all additions, etc.

[1] [2] When we sustained the constitutionality of the Natural Gas Act in the Natural Gas Pipeline Co. case, we stated that the 'authority of Congress to regulate the prices of commodities in interstate commerce is at least as great under the Fifth Amendment as is that of the states under the Fourteenth to regulate the prices of commodities in intrastate commerce.' 315 U.S. at page 582, 62 S.Ct. at page 741, 86 L.Ed. 1037. Rate-making is indeed but one species of price-fixing. Munn v. Illinois, 94 U.S. 113, 134, 24 L.Ed. 77. The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. But the fact that the value is reduced does not mean that the regulation is invalid. Block v. Hirsh, 256 U.S. 135, 155-157, 41 S.Ct. 458, 459, 460, 65 L.Ed. 865, 16 A.L.R. 165; Nebbia v. New York, 291 U.S. 502, 523-539, 54 S.Ct. 505, 509-517, 78 L.Ed. 940, 89 A.L.R. 1469, and cases cited. It does, however, indicate that 'fair value' is the end product of the process of rate-making not the starting point as the Circuit Court of Appeals held. The heart of the matter is that rates cannot be made to depend upon 'fair value' when the value of the going enterprise depends on earnings under whatever rates may be anticipated. [FN9]

FN9 We recently stated that the meaning of the word 'value' is to be gathered 'from the purpose for which a valuation is being made. Thus the question in a valuation for rate making is how much a utility will be allowed to earn. The basic question in a valuation for reorganization purposes is how much the enterprise in all probability can earn.' Institutional Investors v. Chicago, M., St. P. & P.R. Co., 318 U.S. 523, 540, 63 S.Ct. 727, 738.

***602** [3] [4] [5] [6] [7] We held in Federal Power Commission v. Natural Gas Pipeline Co., supra, that the Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' Id., 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. And when the Commission's order is challenged in the courts, the question is whether that order 'viewed in its entirety' meets the requirements of the Act. Id., 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling. Cf. ****288**Los Angeles Gas & Electric Corp. v. Railroad Commission, 289 U.S. 287, 304, 305, 314, 53 S.Ct. 637, 643, 644, 647, 77 L.Ed. 1180; West Ohio Gas Co. v. Public Utilities Commission (No. 1), 294 U.S. 63, 70, 55 S.Ct. 316, 320, 79 L.Ed. 761; West v. Chesapeake & Potomac Tel. Co., 295 U.S. 662, 692, 693, 55 S.Ct. 894, 906, 907, 79 L.Ed. 1640 (dissenting opinion). It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important. Moreover, the Commission's order does not become suspect by reason of the fact that it is challenged. It is the product of expert judgment which carries a presumption of validity. And he who would upset the rate order under the Act carries the heavy burden of making a convincing showing that it is invalid because it is unjust and unreasonable in its consequences. Cf. Railroad Commission v. Cumberland Tel. & T. Co., 212 U.S. 414, 29 S.Ct. 357, 53 L.Ed. 577; Lindheimer v. Illinois Bell Tel. Co., supra, 292 U.S. at pages 164, 169, 54 S.Ct. at pages 663, 665, 78 L.Ed. 1182; Railroad Commission v. Pacific Gas & E. Co., 302 U.S. 388, 401, 58 S.Ct. 334, 341, 82 L.Ed. 319.

***603** [8] [9] The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745, 86 L.Ed. 1037. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346, 12 S.Ct. 400, 402, 36 L.Ed. 176. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. See State of Missouri ex rel. South-western Bell Tel. Co. v. Public Service Commission, 262 U.S. 276, 291, 43 S.Ct. 544, 547, 67 L.Ed. 981, 31 A.L.R. 807 (Mr. Justice Brandeis concurring). The conditions under which more or less might be allowed are not important here. Nor is it important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at. For we are of the view that the end result in this case cannot be condemned under the Act as unjust and unreasonable from the investor or company viewpoint.

We have already noted that Hope is a wholly owned subsidiary of the Standard Oil Co. (N.J.). It has no securities outstanding except stock. All of that stock has been owned by Standard since 1908. The par amount presently outstanding is approximately $28,000,000 as compared with the rate base of $33,712,526 established by ***604** the Commission. Of the total outstanding stock $11,000,000 was issued in stock dividends. The balance, or about $17,000,000, was issued for cash or other assets. During the four decades of its operations Hope has paid over $97,000,000 in cash dividends. It had, moreover, accumulated by 1940 an earned surplus of about $8,000,000. It had thus earned the total investment in the company nearly seven times. Down to 1940 it earned over 20% per year on the average annual amount of its capital stock issued for cash or other assets. On an average invested capital of some $23,000,000 Hope's average earnings have been about 12% a year. And during this period it had accumulated in addition reserves for depletion and depreciation of about $46,000,000. Furthermore, during 1939, 1940 and 1941, Hope paid dividends of 10% on its stock. And in the year 1942, during about half of which the lower rates were in effect, it paid dividends of 7 1/2%. From 1939-1942 its earned surplus increased from $5,250,000 to about $13,700,000, i.e., to almost half the par value of its outstanding stock.

As we have noted, the Commission fixed a rate of return which permits Hope to earn $2,191,314 annually. In determining that amount it stressed the importance of maintaining the financial integrity of the ****289** company. It considered the financial history of Hope and a vast array of data bearing on the natural gas industry, related businesses, and general economic conditions. It noted that the yields on better issues of bonds of natural gas companies sold in the last few years were 'close to 3 per cent', 44 P.U.R.,N.S., at page 33. It stated that the company was a 'seasoned enterprise whose risks have been minimized' by adequate provisions for depletion and depreciation (past and present) with 'concurrent high profits', by 'protected established markets, through affiliated distribution companies, in populous and industralized areas', and by a supply of gas locally to meet all requirements,***605** 'except on certain peak days in the winter, which it is feasible to supplement in the future with gas from other sources.' Id., 44 P.U.R.,N.S., at page 33. The Commission concluded, 'The company's efficient management, established markets, financial record, affiliations, and its prospective business place it in a strong position to attract capital upon favorable terms when it is required.' Id., 44 P.U.R.,N.S., at page 33.

[10] [11] [12] In view of these various considerations we cannot say that an annual return of $2,191,314 is not 'just and reasonable' within the meaning of the Act. Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid, even though they might produce only a meager return on the so-called 'fair value' rate base. In that connection it will be recalled that Hope contended for a rate base of $66,000,000 computed on reproduction cost new. The Commission points out that if that rate base were accepted, Hope's average rate of return for the four-year period from 1937-1940 would amount to 3.27%. During that period Hope earned an annual average return of about 9% on the average investment. It asked for no rate increases. Its properties were well maintained and operated. As the Commission says such a modest rate of 3.27% suggests an 'inflation of the base on which the rate has been computed.' Dayton Power & Light Co. v. Public Utilities Commission, 292 U.S. 290, 312, 54 S.Ct. 647, 657, 78 L.Ed. 1267. Cf. Lindheimer v. Illinois Bell Tel. Co., supra, 292 U.S. at page 164, 54 S.Ct. at page 663, 78 L.Ed. 1182. The incongruity between the actual operations and the return computed on the basis of reproduction cost suggests that the Commission was wholly justified in rejecting the latter as the measure of the rate base.

In view of this disposition of the controversy we need not stop to inquire whether the failure of the Commission to add the $17,000,000 of well-drilling and other costs to ***606** the rate base was consistent with the prudent investment theory as developed and applied in particular cases.

[13] [14] [15] Only a word need be added respecting depletion and depreciation. We held in the Natural Gas Pipeline Co. case that there was no constitutional requirement 'that the owner who embarks in a wasting-asset business of limited life shall receive at the end more than he has put into it.' 315 U.S. at page 593, 62 S.C. at page 746, 86 L.Ed. 1037. The Circuit Court of Appeals did not think that that rule was applicable here because Hope was a utility required to continue its service to the public and not scheduled to end its business on a day certain as was stipulated to be true of the Natural Gas Pipeline Co. But that distinction is quite immaterial. The ultimate exhaustion of the supply is inevitable in the case of all natural gas companies. Moreover, this Court recognized in Lindheimer v. Illinois Bell Tel. Co., supra, the propriety of basing annual depreciation on cost. [FN10] By such a procedure the ****290** utility is made whole and the integrity of its investment maintained. [FN11] No more is required. [FN12] We cannot approve the contrary holding ***607** of United Railways & Electric Co. v. West, 280 U.S. 234, 253, 254, 50 S.Ct. 123, 126, 127, 74 L.Ed. 390. Since there are no constitutional requirements more exacting than the standards of the Act, a rate order which conforms to the latter does not run afoul of the former.

FN10 Chief Justice Hughes said in that case (292 U.S. at pages 168, 169, 54 S.Ct. at page 665, 78 L.Ed. 1182): 'If the predictions of service life were entirely accurate and retirements were made when and as these predictions were precisely fulfilled, the depreciation reserve would represent the consumption of capital, on a cost basis, according to the method which spreads that loss over the respective service periods. But if the amounts charged to operating expenses and credited to the account for depreciation reserve are excessive, to that extent subscribers for the telephone service are required to provide, in effect, capital contributions, not to make good losses incurred by the utility in the service rendered and thus to keep its investment unimpaired, but to secure additional plant and equipment upon which the utility expects a return.'

FN11 See Mr. Justice Brandeis (dissenting) in United Railways & Electric Co. v. West, 280 U.S. 234, 259-288, 50 S.Ct. 123, 128-138, 74 L.Ed. 390, for an extended analysis of the problem.

FN12 It should be noted that the Act provides no specific rule governing depletion and depreciation. Sec. 9(a) merely states that the

Commission 'may from time to time ascertain and determine, and by order fix, the proper and adequate rates of depreciation and amortization of the several classes of property of each natural-gas company used or useful in the production, transportation, or sale of natural gas.'

The Position of West Virginia. The State of West Virginia, as well as its Public Service Commission, intervened in the proceedings before the Commission and participated in the hearings before it. They have also filed a brief amicus curiae here and have participated in the argument at the bar. Their contention is that the result achieved by the rate order 'brings consequences which are unjust to West Virginia and its citizens' and which 'unfairly depress the value of gas, gas lands and gas leaseholds, unduly restrict development of their natural resources, and arbitrarily transfer their properties to the residents of other states without just compensation therefor.'

West Virginia points out that the Hope Natural Gas Co. holds a large number of leases on both producing and unoperated properties. The owner or grantor receives from the operator or grantee delay rentals as compensation for postponed drilling. When a producing well is successfully brought in, the gas lease customarily continues indefinitely for the life of the field. In that case the operator pays a stipulated gas-well rental or in some cases a gas royalty equivalent to one-eighth of the gas marketed. [FN13] Both the owner and operator have valuable property interests in the gas which are separately taxable under West Virginia law. The contention is that the reversionary interests in the leaseholds should be represented in the rate proceedings since it is their gas which is being sold in interstate ***608** commerce. It is argued, moreover, that the owners of the reversionary interests should have the benefit of the 'discovery value' of the gas leaseholds, not the interstate consumers. Furthermore, West Virginia contends that the Commission in fixing a rate for natural gas produced in that State should consider the effect of the rate order on the economy of West Virginia. It is pointed out that gas is a wasting asset with a rapidly diminishing supply. As a result West Virginia's gas deposits are becoming increasingly valuable. Nevertheless the rate fixed by the Commission reduces that value. And that reduction, it is said, has severe repercussions on the economy of the State. It is argued in the first place that as a result of this rate reduction Hope's West Virginia property taxes may be decreased in view of the relevance which earnings have under West Virginia law in the assessment of property for tax purposes. [FN14] Secondly, it is pointed out that West Virginia has a production tax [FN15] on the 'value' of the gas exported from the State. And we are told that for purposes of that tax 'value' becomes under West Virginia law 'practically the substantial equivalent of market value.' Thus West Virginia argues that undervaluation of Hope's gas leaseholds will cost the State many thousands of dollars in taxes. The effect, it is urged, is to impair West Virginia's tax structure for the benefit of Ohio and Pennsylvania consumers. West Virginia emphasizes, moreover, its deep interest in the conservation of its natural resources including its natural gas. It says that a reduction of the value of these leasehold values will jeopardize these conservation policies in three respects: (1) ****291** exploratory development of new fields will be discouraged; (2) abandonment of lowyield high-cost marginal wells will be hastened; and (3) secondary recovery of oil will be hampered. ***609** Furthermore, West Virginia contends that the reduced valuation will harm one of the great industries of the State and that harm to that industry must inevitably affect the welfare of the citizens of the State. It is also pointed out that West Virginia has a large interest in coal and oil as well as in gas and that these forms of fuel are competitive. When the price of gas is materially cheapened, consumers turn to that fuel in preference to the others. As a result this lowering of the price of natural gas will have the effect of depreciating the price of West Virginia coal and oil.

FN13 See Simonton, The Nature of the Interest of the Grantee Under an Oil and Gas Lease (1918), 25 W.Va.L.Quar. 295.

FN14 West Penn Power Co. v. Board of Review, 112 W.Va. 442, 164 S.E. 862.

FN15 W.Va.Rev.Code of 1943, ch. 11. Art. 13, ss 2a, 3a.

West Virginia insists that in neglecting this aspect of the problem the Commission failed to perform the function which Congress entrusted to it and that the case should be remanded to the Commission for a modification of its order. [FN16]

FN16 West Virginia suggests as a possible solution (1) that a 'going concern value' of the company's tangible assets be included in the rate base and (2) that the fair market value of gas delivered to customers be added to the outlay for operating expenses and taxes.

We have considered these contentions at length in view of the earnestness with which they have been urged upon us. We have searched the legislative history of the Natural

Gas Act for any indication that Congress entrusted to the Commission the various considerations which West Virginia has advanced here. And our conclusion is that Congress did not.

[16] [17] We pointed out in Illinois Natural Gas Co. v. Central Illinois Public Service Co., 314 U.S. 498, 506, 62 S.Ct. 384, 387, 86 L.Ed. 371, that the purpose of the Natural Gas Act was to provide, 'through the exercise of the national power over interstate commerce, an agency for regulating the wholesale distribution to public service companies of natural gas moving interstate, which this Court had declared to be interstate commerce not subject to certain types of state regulation.' As stated in the House Report the 'basic purpose' of this legislation was 'to occupy' the field in which such cases as ***610**State of Missouri v. Kansas Natural Gas Co., 265 U.S. 298, 44 S.Ct. 544, 68 L.Ed. 1027, and Public Utilities Commission v. Attleboro Steam & Electric Co., 273 U.S. 83, 47 S.Ct. 294, 71 L.Ed. 549, had held the States might not act. H.Rep. No. 709, 75th Cong., 1st Sess., p. 2. In accomplishing that purpose the bill was designed to take 'no authority from State commissions' and was 'so drawn as to complement and in no manner usurp State regulatory authority.' Id., p. 2. And the Federal Power Commission was given no authority over the 'production or gathering of natural gas.' s 1(b).

[18] The primary aim of this legislation was to protect consumers against exploitation at the lands of natural gas companies. Due to the hiatus in regulation which resulted from the Kansas Natural Gas Co. case and related decisions state commissions found it difficult or impossible to discover what it cost interstate pipe-line companies to deliver gas within the consuming states; and thus they were thwarted in local regulation. H.Rep., No. 709, supra, p. 3. Moreover, the investigations of the Federal Trade Commission had disclosed that the majority of the pipe-line mileage in the country used to transport natural gas, together with an increasing percentage of the natural gas supply for pipe-line transportation, had been acquired by a handful of holding companies. [FN17] State commissions, independent producers, and communities having or seeking the service were growing quite helpless against these combinations. [FN18] These were the types of problems with which those participating in the hearings were pre-occupied. [FN19] Congress addressed itself to those specific evils.

FN17 S.Doc. 92, Pt. 84-A, ch. XII, Final Report, Federal Trade Commission to the Senate pursuant to S.Res.No. 83, 70th Cong., 1st Sess.

FN18 S.Doc. 92, Pt. 84-A, chs. XII, XIII, op. cit., supra, note 17.

FN19 See Hearings on H.R. 11662, Subcommittee of House Committee on Interstate & Foreign Commerce, 74th Cong., 2d Sess.; Hearings on H.R. 4008, House Committee on Interstate & Foreign Commerce, 75th Cong., 1st Sess.

611** The Federal Power Commission was given*292** broad powers of regulation. The fixing of 'just and reasonable' rates (s 4) with the powers attendant thereto [FN20] was the heart of the new regulatory system. Moreover, the Commission was given certain authority by s 7(a), on a finding that the action was necessary or desirable 'in the public interest,' to require natural gas companies to extend or improve their transportation facilities and to sell gas to any authorized local distributor. By s 7(b) it was given control over the abandonment of facilities or of service. And by s 7(c), as originally enacted, no natural gas company could undertake the construction or extension of any facilities for the transportation of natural gas to a market in which natural gas was already being served by another company, or sell any natural gas in such a market, without obtaining a certificate of public convenience and necessity from the Commission. In passing on such applications for certificates of convenience and necessity the Commission was told by s 7(c), as originally enacted, that it was 'the intention of Congress that natural gas shall be sold in interstate commerce for resale for ultimate public consumption for domestic, commercial, industrial, or any other use at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest.' The latter provision was deleted from s 7(c) when that subsection was amended by the Act of February 7, 1942, 56 Stat. 83. By that amendment limited grandfather rights were granted companies desiring to extend their facilities and services over the routes or within the area which they were already serving. Moreover, s 7(c) was broadened so as to require certificates***612** of public convenience and necessity not only where the extensions were being made to markets in which natural gas was already being sold by another company but in other situations as well.

FN20 The power to investigate and ascertain the 'actual legitimate cost' of property (s 6), the requirement as to books and records (s 8), control over rates of depreciation (s 9), the requirements for periodic and special reports (s 10), the broad powers of investigation (s 14) are among the chief powers supporting the rate making function.

[19] These provisions were plainly designed to protect the consumer interests against exploitation at the hands of private natural gas companies. When it comes to cases of abandonment or of extensions of facilities or service, we may assume that, apart from the express exemptions FN21 contained in s 7, considerations of conservation are material to the issuance of certificates of public convenience and necessity. But the Commission was not asked here for a certificate of public convenience and necessity under s 7 for any proposed construction or extension. It was faced with a determination of the amount which a private operator should be allowed to earn from the sale of natural gas across state lines through an established distribution system. Secs. 4 and 5, not s 7, provide the standards for that determination. We cannot find in the words of the Act or in its history the slightest intimation or suggestion that the exploitation of consumers by private operators through the maintenance of high rates should be allowed to continue provided the producing states obtain indirect benefits from it. That apparently was the Commission's view of the matter, for the same arguments advanced here were presented to the Commission and not adopted by it.

FN21 Apart from the grandfather clause contained in s 7(c), there is the provision of s 7(f) that a natural gas company may enlarge or extend its facilities with the 'service area' determined by the Commission without any further authorization.

We do not mean to suggest that Congress was unmindful of the interests of the producing states in their natural gas supplies when it drafted the Natural Gas Act. As we have said, the Act does not intrude on the domain traditionally reserved for control by state commissions; and the Federal Power Commission was given no authority over***613** 'the production or gathering of natural gas.' s 1(b). In addition, Congress recognized the legitimate interests of the States in the conservation of natural gas. By s 11 Congress instructed the Commission to make reports on compacts between two or more States dealing with the conservation, production and transportation of natural gas. FN22 The Commission was also ****293** directed to recommend further legislation appropriate or necessary to carry out any proposed compact and 'to aid in the conservation of natural-gas resources within the United States and in the orderly, equitable, and economic production, transportation, and distribution of natural gas.' s 11(a). Thus Congress was quite aware of the interests of the producing states in their natural gas supplies. FN23 But it left the protection of ***614** those interests to measures other than the maintenance of high rates to private companies. If the Commission is to be compelled to let the stockholders of natural gas companies have a feast so that the producing states may receive crumbs from that table, the present Act must be redesigned. Such a project raises questions of policy which go beyond our province.

FN22 See P.L. 117, approved July 7, 1943, 57 Stat. 383 containing an 'Interstate Compact to Conserve Oil and Gas' between Oklahoma, Texas, New Mexico, Illinois, Colorado, and Kansas.

FN23 As we have pointed out, s 7(c) was amended by the Act of February 7, 1942, 56 Stat. 83, so as to require certificates of public convenience and necessity not only where the extensions were being made to markets in which natural gas was already being sold by another company but to other situations as well. Considerations of conservation entered into the proposal to give the Act that broader scope. H.Rep.No. 1290, 77th Cong. 1st Sess., pp. 2, 3. And see Annual Report, Federal Power Commission (1940) pp. 79, 80; Baum, The Federal Power Commission and State Utility Regulation (1942), p. 261.

The bill amending s 7(c) originally contained a subsection (h) reading as follows: 'Nothing contained in this section shall be construed to affect the authority of a State within which natural gas is produced to authorize or require the construction or extension of facilities for the transportation and sale of such gas within such State: Provided, however, That the Commission, after a hearing upon complaint or upon its own motion, may by order forbid any intrastate construction or extension by any natural-gas company which it shall find will prevent such company from rendering adequate service to its customers in interstate or foreign commerce in territory already being served.' See Hearings on H.R. 5249, House Committee on Interstate & Foreign Commerce, 77th Cong., 1st Sess., pp. 7, 11, 21, 29, 32, 33. In explanation of its deletion the House Committee Report stated, pp. 4, 5: 'The increasingly important problems raised by the desire of several States to regulate the use of the natural gas produced therein in the interest of consumers within such States, as against the Federal power to regulate interstate commerce in the interest of both interstate and intrastate consumers, are deemed by the committee to warrant further intensive study and probably a more retailed and comprehensive plan for the handling thereof than that which would have been provided by the stricken subsection.'

[20] It is hardly necessary to add that a limitation on the net earnings of a natural gas company from its interstate business is not a limitation on the power of the producing state either to safeguard its tax revenues from that industry FN24 or to protect the interests of those who sell their gas to the interstate operator. FN25 The return which **294 the Commission*615 allowed was the net return after all such charges.

FN24 We have noted that in the annual operating expenses of some $16,000.000 the Commission included West Virginia and federal taxes. And in the net increase of $421,160 over 1940 operating expenses allowed by the Commission was some $80,000 for increased West Virginia property taxes. The adequacy of these amounts has not been challenged here.

FN25 The Commission included in the aggregate annual operating expenses which it allowed some $8,500,000 for gas purchased. It also allowed about $1,400,000 for natural gas production and about $600,000 for exploration and development.

It is suggested, however, that the Commission in ascertaining the cost of Hope's natural gas production plant proceeded contrary to s 1(b) which provides that the Act shall not apply to 'the production or gathering of natural gas'. But such valuation, like the provisions for operating expenses, is essential to the rate-making function as customarily performed in this country. Cf. Smith, The Control of Power Rates in the United States and England (1932), 159 The Annals 101. Indeed s 14(b) of the Act gives the Commission the power to 'determine the propriety and reasonableness of the inclusion in operating expenses, capital, or surplus of all delay rentals or other forms of rental or compensation for unoperated lands and leases.'

It is suggested that the Commission has failed to perform its duty under the Act in that it has not allowed a return for gas production that will be enough to induce private enterprise to perform completely and efficiently its functions for the public. The Commission, however, was not oblivious of those matters. It considered them. It allowed, for example, delay rentals and exploration and development costs in operating expenses. FN26 No serious attempt has been made here to show that they are inadequate. We certainly cannot say that they are, unless we are to substitute our opinions for the expert judgment of the administrators to whom Congress entrusted the decision. Moreover, if in light of experience they turn out to be inadequate for development of new sources of supply, the doors of the Commission are open for increased allowances. This is not an order for all time. The Act contains machinery for obtaining rate adjustments. s 4.

FN26 See note 25, supra.

[21] [22] But it is said that the Commission placed too low a rate on gas for industrial purposes as compared with gas for domestic purposes and that industrial uses should be discouraged. It should be noted in the first place that the rates which the Commission has fixed are Hope's interstate wholesale rates to distributors not interstate rates to industrial users FN27 and domestic consumers. We hardly *616 can assume, in view of the history of the Act and its provisions, that the resales intrastate by the customer companies which distribute the gas to ultimate consumers in Ohio and Pennsylvania are subject to the rate-making powers of the Commission. FN28 But in any event those rates are not in issue here. Moreover, we fail to find in the power to fix 'just and reasonable' rates the power to fix rates which will disallow or discourage resales for industrial use. The Committee Report stated that the Act provided 'for regulation along recognized and more or less standardized lines' and that there was 'nothing novel in its provisions'. H.Rep.No.709, supra, p. 3. Yet if we are now to tell the Commission to fix the rates so as to discourage particular uses, we would indeed be injecting into a rate case a 'novel' doctrine which has no express statutory sanction. The same would be true if we were to hold that the wasting-asset nature of the industry required the maintenance of the level of rates so that natural gas companies could make a greater profit on each unit of gas sold. Such theories of rate-making for this industry may or may not be desirable. The difficulty is that s 4(a) and s 5(a) contain only the conventional standards of rate-making for natural gas companies. FN29 The *617 Act of February 7, 1942, by broadening s 7 gave the Commission some additional authority to deal with the conservation aspects of the problem. FN30 But s 4(a) and s 5(a) were not changed. If the standard**295 of 'just and reasonable' is to sanction the maintenance of high rates by a natural gas company because they restrict the use of natural gas for certain purposes, the Act must be further amended.

FN27 The Commission has expressed doubts over its power to fix rates on 'direct sales to industries' from interstate pipelines as distinguished from 'sales for resale to the industrial customers of distributing companies.' Annual Report, Federal Power Commission (1940), p. 11.

FN28. Sec. 1(b) of the Act provides: 'The provisions of this Act shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.' And see s 2(6), defining a 'natural-gas company', and H.Rep.No. 709, supra, pp. 2, 3.

FN29 The wasting-asset characteristic of the industry was recognized prior to the Act as requiring the inclusion of a depletion allowance among operating expenses. See Columbus Gas & Fuel Co. v. Public Utilities Commission, 292 U.S. 398, 404, 405, 54 S.Ct. 763, 766, 767, 78 L.Ed. 1327, 91 A.L.R. 1403. But no such theory of rate-making for natural gas companies as is now suggested emerged from the cases arising during the earlier period of regulation.

FN30 The Commission has been alert to the problems of conservation in its administration of the Act. It has indeed suggested that it might be wise to restrict the use of natural gas 'by functions rather than by areas.' Annual Report (1940) p. 79.

The Commission stated in that connection that natural gas was particularly adapted to certain industrial uses. But it added that the general use of such gas 'under boilers for the production of steam' is 'under most circumstances of very questionable social economy.' Ibid.

[23] [24] It is finally suggested that the rates charged by Hope are discriminatory as against domestic users and in favor of industrial users. That charge is apparently based on s 4(b) of the Act which forbids natural gas companies from maintaining 'any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.' The power of the Commission to eliminate any such unreasonable differences or discriminations is plain. s 5(a). The Commission, however, made no findings under s 4(b). Its failure in that regard was not challenged in the petition to review. And it has not been raised or argued here by any party. Hence the problem of discrimination has no proper place in the present decision. It will be time enough to pass on that issue when it is presented to us. Congress has entrusted the administration of the Act to the Commission not to the courts. Apart from the requirements of judicial review it is not ***618** for us to advise the Commission how to discharge its functions.

Findings as to the Lawfulness of Past Rates. As we have noted, the Commission made certain findings as to the lawfulness of past rates which Hope had charged its interstate customers. Those findings were made on the complaint of the City of Cleveland and in aid of state regulation. It is conceded that under the Act the Commission has no power to make reparation orders. And its power to fix rates admittedly is limited to those 'to be thereafter observed and in force.' s 5(a). But the Commission maintains that it has the power to make findings as to the lawfulness of past rates even though it has no power to fix those rates. [FN31] However that may be, we do not think that these findings were reviewable under s 19(b) of the Act. That section gives any party 'aggrieved by an order' of the Commission a review 'of such order' in the circuit court of appeals for the circuit where the natural gas company is located or has its principal place of business or in the United States Court of Appeals for the District of Columbia. We do not think that the findings in question fall within that category.

FN31 The argument is that s 4(a) makes 'unlawful' the charging of any rate that is not just and reasonable. And s 14(a) gives the Commission power to investigate any matter 'which it may find necessary or proper in order to determine whether any person has violated' any provision of the Act. Moreover, s 5(b) gives the Commission power to investigate and determine the cost of production or transportation of natural gas in cases where it has 'no authority to establish a rate governing the transportation or sale of such natural gas.' And s 17(c) directs the Commission to 'make available to the several State commissions such information and reports as may be of assistance in State regulation of natural-gas companies.' For a discussion of these points by the Commission see 44 P.U.R.,N.S., at pages 34, 35.

[25] [26] The Court recently summarized the various types of administrative action or determination reviewable as orders under the Urgent Deficiencies Act of October 22, ***619** 1913, 28 U.S.C. ss 45, 47a, 28 U.S.C.A. ss 45, 47a, and kindred statutory provisions. Rochester Tel. Corp. v. United States, 307 U.S. 125, 59 S.Ct. 754, 83 L.Ed. 1147. It was there pointed out that where 'the order sought to be reviewed does not of itself adversely affect complainant but only affects his rights adversely on the contingency of future administrative action', it is not

reviewable. Id., 307 U.S. at page 130, 59 S.Ct. at page 757, 83 L.Ed. 1147. The Court said, 'In view of traditional conceptions of federal judicial power, resort to the courts in these situations is either premature or wholly beyond their province.' **296Id., 307 U.S. at page 130, 59 S.Ct. at page 757, 83 L.Ed. 1147. And see United States v. Los Angeles s.l.r. c/o., 273 U.S. 299, 309, 310, 47 S.Ct. 413, 414, 415, 71 L.Ed. 651; Shannahan v. United States, 303 U.S. 596, 58 S.Ct. 732, 82 L.Ed. 1039. These considerations are apposite here. The Commission has no authority to enforce these findings. They are 'the exercise solely of the function of investigation.' United States v. Los Angeles & S.L.R. Co., supra, 273 U.S. at page 310, 47 S.Ct. at page 414, 71 L.Ed. 651. They are only a preliminary, interim step towards possible future action-action not by the Commission but by wholly independent agencies. The outcome of those proceedings may turn on factors other than these findings. These findings may never result in the respondent feeling the pinch of administrative action.

Reversed.

Mr. Justice ROBERTS took no part in the consideration or decision of this case.

Opinion of Mr. Justice BLACK and Mr. Justice MURPHY.

We agree with the Court's opinion and would add nothing to what has been said but for what is patently a wholly gratuitous assertion as to Constitutional law in the dissent of Mr. Justice FRANKFURTER. We refer to the statement that 'Congressional acquiescence to date in the doctrine of Chicago, etc., R. Co. v. Minnesota, supra (134 U.S. 418, 10 S.Ct. 462, 702, 33 L.Ed. 970), may fairly be claimed.' That was the case in which a majority of this Court was finally induced to expand the meaning ***620** of 'due process' so as to give courts power to block efforts of the state and national governments to regulate economic affairs. The present case does not afford a proper occasion to discuss the soundness of that doctrine because, as stated in Mr. Justice FRANKFURTER'S dissent, 'That issue is not here in controversy.' The salutary practice whereby courts do not discuss issues in the abstract applies with peculiar force to Constitutional questions. Since, however, the dissent adverts to a highly controversial due process doctrine and implies its acceptance by Congress, we feel compelled to say that we do not understand that Congress voluntarily has acquiesced in a Constitutional principle of government that courts, rather than legislative bodies, possess final authority over regulation of economic affairs. Even this Court has not always fully embraced that principle, and we wish to repeat that we have never acquiesced in it, and do not now. See Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 599-601, 62 S.Ct. 736, 749, 750, 86 L.Ed. 1037.

Mr. Justice REED, dissenting.

This case involves the problem of rate making under the Natural Gas Act. Added importance arises from the obvious fact that the principles stated are generally applicable to all federal agencies which are entrusted with the determination of rates for utilities. Because my views differ somewhat from those of my brethren, it may be of some value to set them out in a summary form.

The Congress may fix utility rates in situations subject to federal control without regard to any standard except the constitutional standards of due process and for taking private property for public use without just compensation. Wilson v. New, 243 U.S. 332, 350, 37 S.Ct. 298, 302, 61 L.Ed. 755, L.R.A.1917E, 938, Ann.Cas.1918A, 1024. A Commission, however, does not have this freedom of action. Its powers are limited not only by the constitutional standards but also by the standards of the delegation. Here the standard added by the Natural Gas Act is that the rate be 'just ***621** and reasonable.' [FN1] Section 6 [FN2] **297 throws additional light on the meaning of these words.

FN1 Natural Gas Act, s 4(a), 52 Stat. 821, 822, 15 U.S.C. s 717c(a), 15 U.S.C.A. s 717c(a).

FN2 52 Stat. 821, 824, 15 U.S.C. s 717e, 15 U.S.C.A. s 717e:

'(a) The Commission may investigate and ascertain the actual legitimate cost of the property of every natural-gas company, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation and the fair value of such property.

'(b) Every natural-gas company upon request shall file with the Commission an inventory of all or any part of its property and a statement of the original cost thereof, and shall keep the Commission informed regarding the cost of all additions, betterments, extensions, and new construction.'

When the phrase was used by Congress to describe allowable rates, it had relation to something ascertainable. The rates were not left to the whim of the Commission. The rates fixed would produce an annual return and that annual return was to be compared with a theoretical just and reasonable return, all risks considered, on the fair value of the property used and useful in the public service at the time of the determination.

Such an abstract test is not precise. The agency charged with its determination has a wide range before it could properly be said by a court that the agency had disregarded statutory standards or had confiscated the property of the utility for public use. Cf. Chicago, M. & St. P.R. Co. v. Minnesota, 134 U.S. 418, 461-466, 10 S.Ct. 462, 702, 703-705, 33 L.Ed. 970, dissent. This is as Congress intends. Rates are left to an experienced agency particularly competent by training to appraise the amount required.

The decision as to a reasonable return had not been a source of great difficulty, for borrowers and lenders reached such agreements daily in a multitude of situations; and although the determination of fair value had been troublesome, its essentials had been worked out in fairness to investor and consumer by the time of the enactment***622** of this Act. Cf. Los Angeles G. & E. Corp. v. Railroad Comm., 289 U.S. 287, 304 et seq., 53 S.Ct. 637, 643 et seq., 77 L.Ed. 1180. The results were well known to Congress and had that body desired to depart from the traditional concepts of fair value and earnings, it would have stated its intention plainly. Helvering v. Griffiths, 318 U.S. 371, 63 S.Ct. 636.

It was already clear that when rates are in dispute, 'earnings produced by rates do not afford a standard for decision.' 289 U.S. at page 305, 53 S.Ct. at page 644, 77 L.Ed. 1180. Historical cost, prudent investment and reproduction cost [FN3] were all relevant factors in determining fair value. Indeed, disregarding the pioneer investor's risk, if prudent investment and reproduction cost were not distorted by changes in price levels or technology, each of them would produce the same result. The realization from the risk of an investment in a speculative field, such as natural gas utilities, should be reflected in the present fair value. [FN4] The amount of evidence to be admitted on any point was of course in the agency's reasonable discretion, and it was free to give its own weight to these or other factors and to determine from all the evidence its own judgment as to the necessary rates.

FN3 'Reproduction cost' has been variously defined, but for rate making purposes the most useful sense seems to be, the minimum amount necessary to create at the time of the inquiry a modern plant capable of rendering equivalent service. See I Bonbright, Valuation of Property (1937) 152. Reproduction cost as the cost of building a replica of an obsolescent plant is not of real significance.

'Prudent investment' is not defined by the Court. It may mean the sum originally put in the enterprise, either with or without additional amounts from excess earnings reinvested in the business.

FN4 It is of no more than bookkeeping significance whether the Commission allows a rate of return commensurate with the risk of the original investment or the lower rate based on current risk and a capitalization reflecting the established earning power of a successful company and the probable cost of duplicating its services. Cf. American T. & T. Co. v. United States, 299 U.S. 232, 57 S.Ct. 170, 81 L.Ed. 142. But the latter is the traditional method.

***623** I agree with the Court in not imposing a rule of prudent investment alone in determining the rate base. This leaves the Commission free, as I understand it, to use any available evidence for its finding of fair value, including both prudent investment and the cost of installing at the present time an efficient system for furnishing the needed utility service.

My disagreement with the Court arises primarily from its view that it makes no ****298** difference how the Commission reached the rate fixed so long as the result is fair and reasonable. For me the statutory command to the Commission is more explicit. Entirely aside from the constitutional problem of whether the Congress could validly delegate its rate making power to the Commission, in toto and without standards, it did legislate in the light of the relation of fair and reasonable to fair value and reasonable return. The Commission must therefore make its findings in observance of that relationship.

The Federal Power Commission did not, as I construe their action, disregard its statutory duty. They heard the evidence relating to historical and reproduction cost and to the reasonable rate of return and they appraised its weight. The evidence of reproduction cost was rejected as unpersuasive, but from the other evidence they found a rate base, which is to me a determination of fair value. On that base the earnings allowed seem fair and reasonable. So far as the Commission went in appraising the property employed in the service, I find nothing in the result which indicates confiscation, unfairness or unreasonableness. Good administration of rate making agencies under this method would avoid undue delay and render revaluations unnecessary except after violent fluctuations of price levels. Rate making under this method has been subjected to criticism. But until Congress changes the standards for the agencies, these rate making bodies should continue the conventional theory of rate ***624** making. It will probably be simpler to improve present methods than to devise new ones.

But a major error, I think was committed in the disregard by the Commission of the investment in exploratory operations and other recognized capital costs. These were not considered by the Commission because they were charged to operating expenses by the company at a time when it was unregulated. Congress did not direct the Commission in rate making to deduct from the rate base capital investment which had been recovered during the unregulated period through excess earnings. In my view this part of the investment should no more have been disregarded in the rate base than any other capital investment which previously had been recovered and paid out in dividends or placed to surplus. Even if prudent investment throughout the life of the property is accepted as the formula for figuring the rate base, it seems to me illogical to throw out the admittedly prudent cost of part of the property because the earnings in the unregulated period had been sufficient to return the prudent cost to the investors over and above a reasonable return. What would the answer be under the theory of the Commission and the Court, if the only prudent investment in this utility had been the seventeen million capital charges which are now disallowed?

For the reasons heretofore stated, I should affirm the action of the Circuit Court of Appeals in returning the proceeding to the Commission for further consideration and should direct the Commission to accept the disallowed capital investment in determining the fair value for rate making purposes.

Mr. Justice FRANKFURTER, dissenting.
My brother JACKSON has analyzed with particularity the economic and social aspects of natural gas as well as ***625** the difficulties which led to the enactment of the Natural Gas Act, especially those arising out of the abortive attempts of States to regulate natural gas utilities. The Natural Gas Act of 1938 should receive application in the light of this analysis, and Mr. Justice JACKSON has, I believe, drawn relevant inferences regarding the duty of the Federal Power Commission in fixing natural gas rates. His exposition seems to me unanswered, and I shall say only a few words to emphasize my basic agreement with him.

For our society the needs that are met by public utilities are as truly public services as the traditional governmental functions of police and justice. They are not less so when these services are rendered by private enterprise under governmental regulation. Who ultimately determines the ways of regulation, is the decisive aspect in the public supervision of privately-owned utilities. Foreshadowed nearly sixty years ago, Railroad Commission Cases (Stone v. Farmers' Loan & Trust Co.), 116 U.S. 307, 331, 6 S.Ct. 334, 344, 388, 1191, 29 L.Ed. 636, it was decided more than fifty ****299** years ago that the final say under the Constitution lies with the judiciary and not the legislature. Chicago, etc., R. Co. v. Minnesota , 134 U.S. 418, 10 S.Ct. 462, 702, 33 L.Ed. 970.

While legal issues touching the proper distribution of governmental powers under the Constitution may always be raised, Congressional acquiescence to date in the doctrine of Chicago, etc., R. Co. v. Minnesota, supra, may fairly be claimed. But in any event that issue is not here in controversy. As pointed out in the opinions of my brethren, Congress has given only limited authority to the Federal Power Commission and made the exercise of that authority subject to judicial review. The Commission is authorized to fix rates chargeable for natural gas. But the rates that it can fix must be 'just and reasonable'. s 5 of the Natural Gas Act, 15 U.S.C. s 717d, 15 U.S.C.A. s 717d. Instead of making the Commission's rate determinations final, Congress***626** specifically provided for court review of such orders. To be sure, 'the finding of the Commission as to the facts, if supported by substantial evidence' was made 'conclusive', s 19 of the Act, 15 U.S.C. s 717r; 15 U.S.C.A. s 717r. But obedience of the requirement of Congress that rates be 'just and reasonable' is not an issue of fact of which the Commission's own determination is conclusive. Otherwise, there would be nothing for a court to review except questions of compliance with the procedural provisions of the Natural Gas Act. Congress might have seen fit so to cast its legislation. But it has not done so. It has committed to the administration of the Federal Power Commission the duty of applying standards of fair dealing and of reasonableness relevant to the purposes expressed by the Natural Gas Act. The requirement that rates must be 'just and reasonable' means just and reasonable in relation to appropriate standards. Otherwise Congress would have directed the Commission to fix such rates as in the judgment of the Commission are just and reasonable; it would not have also provided that such determinations by the Commission are subject to court review.

To what sources then are the Commission and the courts to go for ascertaining the standards relevant to the regulation of natural gas rates? It is at this point that Mr. Justice JACKSON'S analysis seems to me pertinent. There appear to be two alternatives. Either the fixing of natural gas rates must be left to the unguided discretion of the Commission so long as the rates it fixes do not reveal a glaringly had prophecy of the ability of a regulated utility to continue its service in the future. Or the Commission's rate orders must be founded on due consideration of all the elements of the public interest which the production and distribution of natural gas involve just because it is natural gas. These elements are reflected in the Natural Gas Act, if that Act be applied as an entirety. See, for ***627** instance, ss 4(a)(b)(c)(d), 6, and 11, 15 U.S.C. ss 717c(a)(b)(c)(d), 717e, and 717j, 15 U.S.C.A. ss 717c(a-d), 717e, 717j. Of course the statute is not concerned with abstract theories of ratemaking. But its very foundation is the 'public interest', and the public interest is a texture of multiple strands. It includes more than contemporary investors and contemporary consumers. The needs to be served are not restricted to immediacy, and social as well as economic costs must be counted.

It will not do to say that it must all be left to the skill of experts. Expertise is a rational process and a rational process implies expressed reasons for judgment. It will little advance the public interest to substitute for the hodge-podge of the rule in Smyth v. Ames, 169 U.S. 466, 18 S.Ct. 418, 42 L.Ed. 819, an encouragement of conscious obscurity or confusion in reaching a result, on the assumption that so long as the result appears harmless its basis is irrelevant. That may be an appropriate attitude when state action is challenged as unconstitutional. Cf. Driscoll v. Edison Light & Power Co., 307 U.S. 104, 59 S.Ct. 715, 83 L.Ed. 1134. But it is not to be assumed that it was the design of Congress to make the accommodation of the conflicting interests exposed in Mr. Justice JACKSON'S opinion the occasion for a blind clash of forces or a partial assessment of relevant factors, either before the Commission or here.

The objection to the Commission's action is not that the rates it granted were too low but that the range of its vision was too narrow. And since the issues before the Commission involved no less than the ****300** total public interest, the proceedings before it should not be judged by narrow conceptions of common law pleading. And so I conclude that the case should be returned to the Commission. In order to enable this Court to discharge its duty of reviewing the Commission's order, the Commission should set forth with explicitness the criteria by which it is guided ***628** in determining that rates are 'just and reasonable', and it should determine the public interest that is in its keeping in the perspective of the considerations set forth by Mr. Justice JACKSON.

By Mr. Justice JACKSON.

Certainly the theory of the court below that ties rate-making to the fair-value-reproduction-cost formula should be overruled as in conflict with Federal Power Commission v. Natural Gas Pipeline Co. [FN1] But the case should, I think, be the occasion for reconsideration of our rate-making doctrine as applied to natural gas and should be returned to the Commission for further consideration in the light thereof.

FN1 315 U.S. 575, 62 S.Ct. 736, 86 L.Ed. 1037.

The Commission appears to have understood the effect of the two opinions in the Pipeline case to be at least authority and perhaps direction to fix natural gas rates by exclusive application of the 'prudent investment' rate base theory. This has no warrant in the opinion of the Chief Justice for the Court, however, which released the Commission from subservience to 'any single formula or combination of formulas' provided its order, 'viewed in its entirety, produces no arbitrary result.' 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. The minority opinion I understood to advocate the 'prudent investment' theory as a sufficient guide in a natural gas case. The view was expressed in the court below that since this opinion was not expressly controverted it must have been approved. [FN2] I disclaim this imputed***629** approval with some particularity, because I attach importance at the very beginning of federal regulation of the natural gas industry to approaching it as the performance of economic functions, not as the performance of legalistic rituals.

FN2 Judge Dobie, dissenting below, pointed out that the majority opinion in the Pipeline case 'contains no express discussion of the Prudent Investment Theory' and that the concurring opinion contained a clear one, and said, 'It is difficult for me to believe that the majority of the Supreme Court, believing otherwise, would leave such a statement unchallenged.' (134 F.2d 287, 312.) The fact that two other Justices had as matter of record in our books long opposed the reproduction cost theory of rate bases and had commented favorably on the prudent investment theory may have influenced that conclusion. See opinion of Mr. Justice Frankfurter in Driscoll v. Edison Light & Power Co., 307 U.S. 104, 122, 59 S.Ct. 715, 724, 83 L.Ed. 1134, and my brief as Solicitor General in that case. It should be noted, however, that these statements were made, not in a natural gas case, but in an electric power case-a very important distinction, as I shall try to make plain.

I.

Solutions of these cases must consider eccentricities of the industry which gives rise to them and also to the Act of Congress by which they are governed.

The heart of this problem is the elusive, exhaustible, and irreplaceable nature of natural gas itself. Given sufficient money, we can produce any desired amount of railroad, bus, or steamship transportation, or communications facilities, or capacity for generation of electric energy, or for the manufacture of gas of a kind. In the service of such utilities one customer has little concern with the amount taken by another, one's waste will not deprive another, a volume of service and be created equal to demand, and today's demands will not exhaust or lessen capacity to serve tomorrow. But the wealth of Midas and the wit of man cannot produce or reproduce a natural gas field. We cannot even reproduce the gas, for our manufactured product has only about half the heating value per unit of nature's own. [FN3]

FN3 Natural gas from the Appalachian field averages about 1050 to 1150 B.T.U. content, while by-product manufactured gas is about 530 to 540. Moody's Manual of Public Utilities (1943) 1350; Youngberg, Natural Gas (1930) 7.

****301** Natural gas in some quantity is produced in twenty-four states. It is consumed in only thirty-five states, and is ***630** available only to about 7,600,000 consumers. [FN4] Its availability has been more localized than that of any other utility service because it has depended more on the caprice of nature.

FN4 Sen.Rep. No. 1162, 75th Cong., 1st Sess., 2.

The supply of the Hope Company is drawn from that old and rich and vanishing field that flanks the Appalachian mountains. Its center of production is Pennsylvania and West Virginia, with a fringe of lesser production in New York, Ohio, Kentucky, Tennessee, and the north end of Alabama. Oil was discovered in commercial quantities at a depth of only 69 1/2 feet near Titusville, Pennsylvania, in 1859. Its value then was about $16 per barrel. [FN5] The oil branch of the petroleum industry went forward at once, and with unprecedented speed. The area productive of oil and gas was roughed out by the drilling of over 19,000 ‘wildcat’ wells, estimated to have cost over $222,000,000. Of these, over 18,000 or 94.9 per cent, were ‘dry holes.’ About five per cent, or 990 wells, made discoveries of commercial importance, 767 of them resulting chiefly in oil and 223 in gas only. [FN6] Prospecting for many years was a search for oil, and to strike gas was a misfortune. Waste during this period and even later is appalling. Gas was regarded as having no commercial value until about 1882, in which year the total yield was valued only at about $75,000. [FN7] Since then, contrary to oil, which has become cheaper gas in this field has pretty steadily advanced in price.

FN5 Arnold and Kemnitzer, Petroleum in the United States and Possessions (1931) 78.

FN6. Id. at 62-63.

FN7. Id. at 61.

While for many years natural gas had been distributed on a small scale for lighting, [FN8] its acceptance was slow, ***631** facilities for its utilization were primitive, and not until 1885 did it take on the appearance of a substantial industry. [FN9] Soon monopoly of production or markets developed. [FN10] To get gas from the mountain country, where it was largely found, to centers of population, where it was in demand, required very large investment. By ownership of such facilities a few corporate systems, each including several companies, controlled access to markets. Their purchases became the dominating factor in giving a market value to gas produced by many small operators. Hope is the market for over 300 such operators. By 1928 natural gas in the Appalachian field commanded an average price of 21.1 cents per m.c.f. at points of production and was bringing 45.7 cents at points of consumption. [FN11] The companies which controlled markets, however, did not rely on gas purchases alone. They acquired and held in fee or leasehold great acreage in territory proved by ‘wildcat’ drilling. These large marketing system companies as well as many small independent owners and operators have carried on the commercial development of proved territory. The development risks appear from the estimate that up to 1928, 312,318 proved area wells had been sunk in the Appalachian field of which 48,962, or 15.7 per cent, failed to produce oil or gas in commercial quantity. [FN12]

FN8 At Fredonia, New York, in 1821, natural gas was conveyed from a shallow well to some thirty people. The lighthouse at Barcelona Harbor, near what is now Westfield, New York, was at about that time and for many years afterward lighted by gas that issued from a crevice. Report on Utility Corporations by Federal Trade Commission, Sen.Doc. 92, Pt. 84-A, 70th Cong., 1st Sess., 8-9.

FN9 In that year Pennsylvania enacted ‘An Act to provide for the incorporation and regulation of natural gas companies.’ Penn.Laws 1885, No. 32, 15 P.S. s 1981 et seq.

FN10 See Steptoe and Hoffheimer's Memorandum for Governor Cornwell of West Virginia (1917) 25 West Virginia Law Quarterly 257; see also Report on Utility Corporations by

Federal Trade Commission, Sen.Doc. No. 92, Pt. 84-A, 70th Cong., 1st Sess.

FN11 Arnold and Kemnitzer, Petroleum in the United States and Possessions (1931) 73.

FN12. Id. at 63.

***632** With the source of supply thus tapped to serve centers of large demand, like Pittsburgh, Buffalo, Cleveland, Youngstown, Akron, and other industrial communities, the distribution of natural gas fast became big business. Its advantages as a ****302** fuel and its price commended it, and the business yielded a handsome return. All was merry and the goose hung high for consumers and gas companies alike until about the time of the first. World War. Almost unnoticed by the consuming public, the whole Appalachian field passed its peak of production and started to decline. Pennsylvania, which to 1928 had given off about 38 per cent of the natural gas from this field, had its peak in 1905; Ohio, which had produced 14 per cent, had its peak in 1915; and West Virginia, greatest producer of all, with 45 per cent to its credit, reached its peak in 1917. [FN13]

FN13. Id. at 64.

Western New York and Eastern Ohio, on the fringe of the field, had some production but relied heavily on imports from Pennsylvania and West Virginia. Pennsylvania, a producing and exporting state, was a heavy consumer and supplemented her production with imports from West Virginia. West Virginia was a consuming state, but the lion's share of her production was exported. Thus the interest of the states in the North Appalachian supply was in conflict.

Competition among localities to share in the failing supply and the helplessness of state and local authorities in the presence of state lines and corporate complexities is a part of the background of federal intervention in the industry. [FN14] West Virginia took the boldest measure. It legislated a priority in its entire production in favor of its own inhabitants. That was frustrated by an injunction***633** from this Court. [FN15] Throughout the region clashes in the courts and conflicting decisions evidenced public anxiety and confusion. It was held that the New York Public Service Commission did not have power to classify consumers and restrict their use of gas. [FN16] That Commission held that a company could not abandon a part of its territory and still serve the rest. [FN17] Some courts admonished the companies to take action to protect consumers. [FN18] Several courts held that companies, regardless of failing supply, must continue to take on customers, but such compulsory additions were finally held to be within the Public Service Commission's discretion. [FN19] There were attempts to throw up franchises and quit the service, and municipalities resorted to the courts with conflicting results. [FN20] Public service commissions of consuming states were handicapped, for they had no control of the supply. [FN21]

FN14 See Report on Utility Corporations by Federal Trade Commission, Sen.Doc. No. 92, Pt. 84-A, 70th Cong., 1st Sess.

FN15 Commonwealth of Pennsylvania v. West Virginia, 262 U.S. 553, 43 S.Ct. 658, 67 L.Ed. 1117, 32 A.L.R. 300. For conditions there which provoked this legislation, see 25 West Virginia Law Quarterly 257.

FN16 People ex rel. Pavilion Natural Gas Co. v. Public Service Commission, 188 App.Div. 36, 176 N.Y.S. 163.

FN17 Village of Falconer v. Pennsylvania Gas Company, 17 State Department Reports, N.Y., 407.

FN18 See, for example, Public Service Commission v. Iroquois Natural Gas Co., 108 Misc. 696, 178 N.Y.S. 24; Park Abbott Realty Co. v. Iroquois Natural Gas Co., 102 Misc. 266, 168 N.Y.S. 673; Public Service Commission v. Iroquois Natural Gas Co., 189 App.Div. 545, 179 N.Y.S. 230.

FN19 People ex rel. Pennsylvania Gas Co. v. Public Service Commission, 196 App.Div. 514, 189 N.Y.S. 478.

FN20 East Ohio Gas Co. v. Akron, 81 Ohio St. 33, 90 N.E. 40, 26 L.R.A., N.S., 92, 18 Ann.Cas. 332; Village of New-comerstown v. Consolidated Gas Co., 100 Ohio St. 494, 127 N.E. 414; Gress v. Village of Ft. Laramie, 100 Ohio St. 35, 125 N.E. 112, 8 A.L.R. 242; City of Jamestown v. Pennsylvania Gas Co., D.C., 263 F. 437; Id., D.C., 264 F. 1009. See, also, United Fuel Gas Co. v. Railroad Commission, 278 U.S. 300, 308, 49 S.Ct. 150, 152, 73 L.Ed. 390.

FN21 The New York Public Service Commission said: 'While the transportation of natural gas through pipe lines from one state to another state is interstate commerce * * *, Congress has not taken over the regulation of that particular industry. Indeed, it has expressly excepted it from the operation of the Interstate Commerce Commissions Law (Interstate Commerce Commissions Law, section 1). It is quite clear, therefore, that this Commission can not require a Pennsylvania corporation producing gas in Pennsylvania to transport it and deliver it in the State of New York, and that the Interstate Commerce Commission is likewise powerless. If there exists such a power, and it seems that there does, it is a power vested in Congress and by it not yet exercised. There is no available source of supply for the Crystal City Company at present except through purchasing from the Porter Gas Company. It is possible that this Commission might fix a price at which the Potter Gas Company should sell if it sold at all, but as the Commission can not require it to supply gas in the State of New York, the exercise of such a power to fix the price, if such power exists, would merely say, sell at this price or keep out of the State.' Lane v. Crystal City Gas Co., 8 New York Public Service Comm.Reports, Second District, 210, 212.

****303 *634** Shortages during World War I occasioned the first intervention in the natural gas industry by the Federal Government. Under Proclamation of President Wilson the United States Fuel Administrator took control, stopped extensions, classified consumers and established a priority for domestic over industrial use. [FN22] After the war federal control was abandoned. Some cities once served with natural gas became dependent upon mixed gas of reduced heating value and relatively higher price. [FN23]

FN22 Proclamation by the President of September 16, 1918; Rules and Regulations of H. A. Garfield, Fuel Administrator, September 24, 1918.

FN23 For example, the Iroquois Gas Corporation which formerly served Buffalo, New York, with natural gas ranging from 1050 to 1150 b.t.u. per cu. ft., now mixes a by-product gas of between 530 and 540 b.t.u. in proportions to provide a mixed gas of about 900 b.t.u. per cu. ft. For space heating or water heating its charges range from 65 cents for the first m.c.f. per month to 55 cents for all above 25 m.c.f. per month. Moody's Manual of Public Utilities (1943) 1350.

Utilization of natural gas of highest social as well as economic return is domestic use for cooking and water ***635** heating, followed closely by use for space heating in homes. This is the true public utility aspect of the enterprise, and its preservation should be the first concern of regulation. Gas does the family cooking cheaper than any other fuel. [FN24] But its advantages do not end with dollars and cents cost. It is delivered without interruption at the meter as needed and is paid for after it is used. No money is tied up in a supply, and no space is used for storage. It requires no handling, creates no dust, and leaves no ash. It responds to thermostatic control. It ignites easily and immediately develops its maximum heating capacity. These incidental advantages make domestic life more liveable.

FN24 The United States Fuel Administration made the following cooking value comparisons, based on tests made in the Department of Home Economics of Ohio State University:

Natural gas at 1.12 per M. is equivalent to coal at $6.50 per ton.
Natural gas at 2.00 per M. is equivalent to gasoline at 27¢ per gal.
Natural gas at 2.20 per M. is equivalent to electricity at 3¢ per k.w.h.
Natural gas at 2.40 per M. is equivalent to coal oil at 15¢ per gal.
Use and Conservation of Natural Gas, issued by U.S. Fuel Administration (1918) 5.

Industrial use is induced less by these qualities than by low cost in competition with other fuels. Of the gas exported from West Virginia by the Hope Company a very substantial part is used by industries. This wholesale use speeds exhaustion of supply and displaces other fuels. Coal miners and the coal industry, a large part of whose costs are wages, have complained of unfair competition from low-priced industrial gas produced with relatively little labor cost. [FN25]

FN25 See Brief on Behalf jof Legislation Imposing an Excise Tax on Natural Gas, submitted to N.R.A. by the United Mine Workers of America and the National Coal Association.

Gas rate structures generally have favored industrial users. In 1932, in Ohio, the average yield on gas for domestic consumption was 62.1 cents per m.c.f. and on industrial,***636** 38.7. In Pennsylvania, the figures were 62.9 against 31.7. West Virginia showed the least spread, domestic consumers paying 36.6 cents; and industrial, 27.7. [FN26] Although this spread is less than ****304** in other parts of the United States, [FN27] it can hardly be said to be self-justifying. It certainly is a very great factor in hastening decline of the natural gas supply.

FN26 Brief of National Gas Association and United Mine Workers, supra, note 26, pp. 35, 36, compiled from Bureau of Mines Reports.

FN27 From the source quoted in the preceding note the spread elsewhere is shown to be:

State.	Industrial	Domestic
Illinois.	29.2	1.678
Louisiana.	10.4	59.7
Oklahoma.	11.2	41.5
Texas.	13.1	59.7
Alabama.	17.8	1.227
Georgia.	22.9	1.043

About the time of World War I there were occasional and short-lived efforts by some hard-pressed companies to reverse this discrimination and adopt graduated rates, giving a low rate to quantities adequate for domestic use and graduating it upward to discourage industrial use. FN28 ***637** These rates met opposition from industrial sources, of course, and since diminished revenues from industrial sources tended to increase the domestic price, they met little popular or commission favor. The fact is that neither the gas companies nor the consumers nor local regulatory bodies can be depended upon to conserve gas. Unless federal regulation will take account of conservation, its efforts seem, as in this case, actually to constitute a new threat to the life of the Appalachian supply.

FN28 In Corning, New York, rates were initiated by the Crystal City Gas Company as follows: 70¢ for the first 5,000 cu. ft. per month; 80¢ from 5,000 to 12,000; $1 for all over 12,000. The Public Service Commission rejected these rates and fixed a flat rate of 58¢ per m.c.f. Lane v. Crystal City Gas Co., 8 New York Public Service Comm. Reports, Second District, 210.
The Pennsylvania Gas Company (National Fuel Gas Company group) also attempted a sliding scale rate for New York consumers, net per month as follows: First 5,000 feet, 35¢ ; second 5,000 feet, 45¢ ; third 5,000 feet, 50¢ ; all above 15,000, 55¢ . This was eventually abandoned, however. The company's present scale in Pennsylvania appears to be reversed to the following net monthly rate; first 3 m.c.f., 75¢ ; next 4 m.c.f., 60¢ ; next 8 m.c.f., 55¢ ; over 15 m.c.f., 50¢ . Moody's Manual of Public Utilities (1943) 1350. In New York it now serves a mixed gas.
For a study of effect of sliding scale rates in reducing consumption see 11 Proceedings of Natural Gas Association of America (1919) 287.

II.

Congress in 1938 decided upon federal regulation of the industry. It did so after an exhaustive investigation of all aspects including failing supply and competition for the use of natural gas intensified by growing scarcity. FN29 Pipelines from the Appalachian area to markets were in the control of a handful of holding company systems. FN30 This created a highly concentrated control of the producers' market and of the consumers' supplies. While holding companies dominated both production and distribution they segregated those activities in separate ***638** subsidiaries, FN31 the effect of which, if not the purpose, was to isolate ****305** some end of the business from the reach of any one state commission. The cost of natural gas to consumers moved steadily upwards over the years, out of proportion to prices of oil, which, except for the element of competition, is produced under somewhat comparable conditions. The public came to feel that the companies were exploiting the growing scarcity of local gas. The problems of this region had much to do with creating the demand for federal regulation.

FN29 See Report on Utility Corporations by Federal Trade Commission, Sen. Doc. 92, Pt. 84-A, 70th Cong., 1st Sess.

FN30 Four holding company systems control over 55 per cent of all natural gas transmission lines in the United States. They are Columbia Gas and Electric Corporation, Cities Service Co., Electric Bond and Share Co., and Standard Oil Co. of New Jersey. Columbia alone controls nearly 25 per cent, and fifteen companies account for over 80 per cent of the total. Report on Utility Corporations by Federal Trade Commission, Sen. Doc. 92, Pt. 84-A, 70th Cong., 1st Sess., 28.

In 1915, so it was reported to the Governor of West

Virginia, 87 per cent of the total gas production of that state was under control of eight companies. Steptoe and Hoffheimer, Legislative Regulation of Natural Gas Supply in West Virginia, 17 West Virginia Law Quarterly 257, 260. Of these, three were subsidiaries of the Columbia system and others were subsidiaries of larger systems. In view of inter-system sales and interlocking interests it may be doubted whether there is much real competition among these companies.

FN31 This pattern with its effects on local regulatory efforts will be observed in our decisions. See United Fuel Gas Co. v. Railroad Commission, 278 U.S. 300, 49 S.Ct. 150, 73 L.Ed. 390; United Fuel Gas Co. v. Public Service Commission, 278 U.S. 322, 49 S.Ct. 157, 73 L.Ed. 402; Dayton Power & Light v. Public Utilities Commission, 292 U.S. 290, 54 S.Ct. 647, 78 L.Ed. 1267; Columbus Gas & Fuel Co. v. Public Utilities Commission, 292 U.S. 398, 54 S.Ct. 763, 78 L.Ed. 1327, 91 A.L.R. 1403, and the present case.

The Natural Gas Act declared the natural gas business to be 'affected with a public interest,' and its regulation 'necessary in the public interest.' [FN32] Originally, and at the time this proceeding was commenced and tried, it also declared 'the intention of Congress that natural gas shall be sold in interstate commerce for resale for ultimate public consumption for domestic, commercial, industrial, or any other use at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest.' [FN33] While this was later dropped, there is nothing to indicate that it was not and is not still an accurate statement of purpose of the Act. Extension or improvement of facilities may be ordered when 'necessary or desirable in the public interest,' abandonment of facilities may be ordered when the supply is 'depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity ***639** permit' abandonment and certain extensions can only be made on finding of 'the present or future public convenience and necessity.' [FN34] The Commission is required to take account of the ultimate use of the gas. Thus it is given power to suspend new schedules as to rates, charges, and classification of services except where the schedules are for the sale of gas 'for resale for industrial use only,' [FN35] which gives the companies greater freedom to increase rates on industrial gas than on domestic gas. More particularly, the Act expressly forbids any undue preference or advantage to any person or 'any unreasonable difference in rates * * * either as between localities or as between classes of service.' [FN36] And the power of the Commission expressly includes that to determine the 'just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force.' [FN37]

FN32 15 U.S.C. s 717(a), 15 U.S.C.A. s 717(a). (Italics supplied throughout this paragraph.)

FN33 s 7(c), 52 Stat. 825, 15 U.S.C.A. s 717f(c).

FN34 15 U.S.C. s 717f, 15 U.S.C.A. s 717f.

FN35 Id., s 717c(e).

FN36 Id., s 717c(b).

FN37 Id., s 717d(a).

In view of the Court's opinion that the Commission in administering the Act may ignore discrimination, it is interesting that in reporting this Bill both the Senate and the House Committees on Interstate Commerce pointed out that in 1934, on a nationwide average the price of natural gas per m.c.f. was 74.6 cents for domestic use, 49.6 cents for commercial use, and 16.9 for industrial use. [FN38] I am not ready to think that supporters of a bill called attention to the striking fact that householders were being charged five times as much for their gas as industrial users only as a situation which the Bill would do nothing to remedy. On the other hand the Act gave to the Commission what the Court aptly describes as 'broad powers of regulation.'

FN38 Sen. Rep. No. 1162, 75th Cong., 1st Sess. 2.

***640** III.

This proceeding was initiated by the Cities of Cleveland and Akron. They alleged that the price charged by Hope for natural gas 'for resale to domestic, commercial and small industrial consumers in Cleveland and elsewhere is excessive, unjust, unreasonable, greatly in excess of the price charged by Hope to nonaffiliated companies at wholesale for resale to domestic, commercial and small industrial consumers, and greatly in excess of the price charged by Hope to East Ohio for resale to certain favored industrial consumers in Ohio, and therefore is further unduly discriminatory between consumers and between classes of service' (italics supplied). The company answered admitting differences in prices to affiliated and nonaffiliated companies and justifying them by differences in conditions of delivery.****306** As to the allegation that the contract price is 'greatly in excess of the price charged by Hope to East Ohio for resale to certain favored industrial consumers in Ohio,' Hope did not deny a price differential, but alleged that industrial gas was not sold to 'favored consumers' but was sold under contract and schedules filed with and approved by the Public Utilities Commission of Ohio, and that certain conditions of delivery made it not 'unduly discriminatory.'

The record shows that in 1940 Hope delivered for industrial consumption 36,523,792 m.c.f. and for domestic and commercial consumption, 50,343,652 m.c.f. I find no separate figure for domestic consumption. It served 43,767 domestic consumers directly, 511,521 through the East Ohio Gas Company, and 154,043 through the Peoples Natural Gas Company, both affiliates owned by the same parent. Its special contracts for industrial consumption, so far as appear, are confined to about a dozen big industries.

***641** Hope is responsible for discrimination as exists in favor of these few industrial consumers. It controls both the resale price and use of industrial gas by virtue of the very interstate sales contracts over which the Commission is exercising its jurisdiction.

Hope's contract with East Ohio Company is an example. Hope agrees to deliver, and the Ohio Company to take, '(a) all natural gas requisite for the supply of the domestic consumers of the Ohio Company; (b) such amounts of natural gas as may be requisite to fulfill contracts made with the consent and approval of the Hope Company by the Ohio Company, or companies which it supplies with natural gas, for the sale of gas upon special terms and conditions for manufacturing purposes.' The Ohio company is required to read domestic customers' meters once a month and meters of industrial customers daily and to furnish all meter readings to Hope. The Hope Company is to have access to meters of all consumers and to all of the Ohio Company's accounts. The domestic consumers of the Ohio Company are to be fully supplied in preference to consumers purchasing for manufacturing purposes and 'Hope Company can be required to supply gas to be used for manufacturing purposes only where the same is sold under special contracts which have first been submitted to and approved in writing by the Hope Company and which expressly provide that natural gas will be supplied thereunder only in so far as the same is not necessary to meet the requirements of domestic consumers supplied through pipe lines of the Ohio Company.' This basic contract was supplemented from time to time, chiefly as to price. The last amendment was in a letter from Hope to East Ohio in 1937. It contained a special discount on industrial gas and a schedule of special industrial contracts, Hope reserving the right to make eliminations therefrom and agreeing that others might be added from time to ***642** time with its approval in writing. It said, 'It is believed that the price concessions contained in this letter, while not based on our costs, are under certain conditions, to our mutual advantage in maintaining and building up the volumes of gas sold by us (italics supplied).' FN39

FN39 The list of East Ohio Gas Company's special industrial contracts thus expressly under Hope's control and their demands are as follows:

****307** The Commission took no note of the charges of discrimination and made no disposition of the issue tendered on this point. It ordered a flat reduction in the price per m.c.f. of all gas delivered by Hope in interstate commerce. It made no limitation, condition, or provision as to what classes of consumers should get the benefit of the reduction. While the cities have accepted and are defending the reduction, it is my view that the discrimination of which they have complained is perpetuated and increased by the order of the Commission and that it violates the Act in so doing.

The Commission's opinion aptly characterizes its entire objective by saying that 'bona fide investment figures now become all-important in the regulation of rates.' It should be noted that the all-importance of this theory is not the result of any instruction from Congress. When the Bill to regulate gas was first before Congress it contained***643** the following: 'In determining just and reasonable rates the Commission shall fix such rate as will allow a fair return upon the actual legitimate prudent cost of the property used and useful for the service in question.' H.R. 5423, 74th Cong., 1st Sess. Title III, s 312(c). Congress rejected this language. See H.R. 5423, s 213 (211(c)), and H.R. Rep. No. 1318, 74th Cong., 1st Sess. 30.

The Commission contends nevertheless that the 'all important' formula for finding a rate base is that of prudent investment. But it excluded from the investment base an amount actually and admittedly invested of some $17,000,000. It did so because it says that the Company recouped these expenditures from customers before the days of regulation from earnings above a fair return. But it would not apply all of such 'excess earnings' to reduce the rate base as one of the Commissioners suggested. The reason for applying excess earnings to reduce the investment base roughly from $69,000,000 to $52,000,000 but refusing to apply them to reduce it from that to some $18,000,000 is not found in a difference in the character of the earnings or in their reinvestment. The reason assigned is a difference in bookkeeping treatment many years before the Company was subject to regulation. The $17,000,000, reinvested chiefly in well drilling, was treated on the books as expense. (The Commission now requires that drilling costs be carried to capital account.) The allowed rate base thus actually was determined by the Company's bookkeeping, not its investment. This attributes a significance to formal classification in account keeping that seems inconsistent with rational rate regulation. FN40 Of ***644** course, the ****308** Commission would not and should not allow a rate base to be inflated by bookkeeping which had improperly capitalized expenses. I have doubts about resting public regulation upon any rule that is to be used or not depending on which side it favors.

FN40 To make a fetish of mere accounting is to shield from examination the deeper causes, forces, movements, and conditions which should govern rates. Even as a recording of current transactions, bookkeeping is hardly an exact science. As a representation of the condition and trend of a business, it uses symbols of certainty to express values that actually are in constant flux. It may be said that in commercial or investment banking or any business extending credit success depends on knowing what not to believe in accounting. Few concerns go into bankruptcy or reorganization whose books do not show them solvent and often even profitable. If one cannot rely on accountancy accurately to disclose past or current conditions of a business, the fallacy of using it as a sole guide to future price policy ought to be apparent. However, our quest for certitude is so ardent that we pay an irrational reverence to a technique which uses symbols of certainty, even though experience again and again warns us that they are delusive. Few writers have ventured to challenge this American idolatry, but see Hamilton, Cost as a standard for Price, 4 Law and Contemporary Problems 321, 323-25. He observes that ‘As the apostle would put it, accountancy is all things to all men. * * * Its purpose determines the character of a system of accounts.’ He analyzes the hypothetical character of accounting and says ‘It was no eternal mold for pecuniary verities handed down from on high. It was-like logic or algebra, or the device of analogy in the law-an ingenious contrivance of the human mind to serve a limited and practical purpose.’ ‘Accountancy is far from being a pecuniary expression of all that is industrial reality. It is an instrument, highly selective in its application, in the service of the institution of money making.’ As to capital account he observes ‘In an enterprise in lusty competition with others of its kind, survival is the thing and the system of accounts has its focus in solvency. * * * Accordingly depreciation, obsolescence, and other factors which carry no immediate threat are matters of lesser concern and the capital account is likely to be regarded as a secondary phenomenon. * * * But in an enterprise, such as a public utility, where continued survival seems assured, solvency is likely to be taken for granted. * * * A persistent and ingenious attention is likely to be directed not so much to securing the upkeep of the physical property as to making it certain that capitalization fails in not one whit to give full recognition to every item that should go into the account.'

***645** The Company on the other hand, has not put its gas fields into its calculations on the present-value basis, although that, it contends, is the only lawful rule for finding a rate base. To do so would result in a rate higher than it has charged or proposes as a matter of good business to charge.

The case before us demonstrates the lack of rational relationship between conventional rate-base formulas and natural gas production and the extremities to which regulating bodies are brought by the effort to rationalize them. The Commission and the Company each stands on a different theory, and neither ventures to carry its theory to logical conclusion as applied to gas fields.

IV.

This order is under judicial review not because we interpose constitutional theories between a State and the business it seeks to regulate, but because Congress put upon the federal courts a duty toward administration of a new federal regulatory Act. If we are to hold that a given rate is reasonable just because the Commission has said it was reasonable, review becomes a costly, time-consuming pageant of no practical value to anyone. If on the other hand we are to bring judgment of our own to the task, we should for the guidance of the regulators and the regulated reveal something of the philosophy, be it legal or economic or social, which guides us. We need not be slaves to a formula but unless we can point out a rational way of reaching our conclusions they can only be accepted as resting on intuition or predilection. I must admit that I possess no instinct jby which to know the ‘reasonable’ from the ‘unreasonable’ in prices and must seek some conscious design for decision.

The Court sustains this order as reasonable, but what makes it so or what could possibly make it otherwise,

***646** I cannot learn. It holds that: 'it is the result reached not the method employed which is controlling'; 'the fact that the method employed to reach that result may contain infirmities is not then important' and it is not 'important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at.' The Court does lean somewhat on considerations of capitalization and dividend history and requirements for dividends on outstanding stock. But I can give no real weight to that for it is generally and I think deservedly in discredit as any guide in rate cases. FN41

FN41 See 2 Bonbright, Valuation of Property (1937) 1112.

Our books already contain so much talk of methods of rationalizing rates that we must appear ambiguous if we announce results without our working methods. We are confronted with regulation of a unique type of enterprise which I think requires considered rejection of much conventional utility doctrine and adoption of concepts of 'just and reasonable' rates and practices and of the 'public interest' that will take account of the peculiarities of the business.

The Court rejects the suggestions of this opinion. It says that the Committees in reporting the bill which became the Act said it provided 'for regulation along recognized and more or less standardized lines' and that there was 'nothing novel in its provisions.' So saying it sustains a rate calculated on a novel variation of a rate base theory which itself had at the time of enactment of the legislation been recognized only in dissenting opinions. Our difference seems to be between unconscious innovation, FN42 and the purposeful ****309** and deliberate innovation I ***647** would make to meet the necessities of regulating the industry before us.

FN42 Bonbright says, '* * * the vice of traditional law lies, not in its adoption of excessively rigid concepts of value and rules of valuation, but rather in its tendency to permit shifts in meaning that are inept, or else that are ill-defined because the judges that make them will not openly admit that they are doing so.' Id., 1170.

Hope's business has two components of quite divergent character. One, while not a conventional common-carrier undertaking, is essentially a transportation enterprise consisting of conveying gas from where it is produced to point of delivery to the buyer. This is a relatively routine operation not differing substantially from many other utility operations. The service is produced by an investment in compression and transmission facilities. Its risks are those of investing in a tested means of conveying a discovered supply of gas to a known market. A rate base calculated on the prudent investment formula would seem a reasonably satisfactory measure for fixing a return from that branch of the business whose service is roughly proportionate to the capital invested. But it has other consequences which must not be overlooked. It gives marketability and hence 'value' to gas owned by the company and gives the pipeline company a large power over the marketability and hence 'value' of the production of others.

The other part of the business-to reduce to possession an adequate supply of natural gas-is of opposite character, being more erratic and irregular and unpredictable in relation to investment than any phase of any other utility business. A thousand feet of gas captured and severed from real estate for delivery to consumers is recognized under our law as property of much the same nature as a ton of coal, a barrel of oil, or a yard of sand. The value to be allowed for it is the real battleground between the investor and consumer. It is from this part of the business that the chief difference between the parties as to a proper rate base arises.

It is necessary to a 'reasonable' price for gas that it be anchored to a rate base of any kind? Why did courts in the first place begin valuing 'rate bases' in order to 'value' something else? The method came into vogue ***648** in fixing rates for transportation service which the public obtained from common carriers. The public received none of the carriers' physical property but did make some use of it. The carriage was often a monopoly so there were no open market criteria as to reasonableness. The 'value' or 'cost' of what was put to use in the service by the carrier was not a remote or irrelevant consideration in making such rates. Moreover the difficulty of appraising an intangible service was thought to be simplified if it could be related to physical property which was visible and measurable and the items of which might have market value. The court hoped to reason from the known to the unknown. But gas fields turn this method topsy turvy. Gas itself is tangible, possessible, and does have a market and a price in the field. The value of the rate base is more elusive than that of gas. It consists of intangibles-leaseholds and freeholds-operated and unoperated-of little use in themselves except as rights to reach and capture gas. Their value lies almost wholly in predictions of discovery, and of price of gas when captured, and bears little relation to cost of tools and supplies and labor to develop it. Gas is what Hope sells and it can be directly priced more reasonably and easily and accurately than the components of a rate base can be valued. Hence the reason for resort to a roundabout way of rate base price fixing does not exist in the case of gas in the field.

But if found, and by whatever method found, a rate base is little help in determining reasonableness of the price of gas. Appraisal of present value of these intangible rights to pursue fugitive gas depends on the value assigned to the gas when captured. The 'present fair value' rate base, generally in ill repute, FN43 is not even ****310** urged by the gas company for valuing its fields.

FN43 'The attempt to regulate rates by reference to a periodic or occasional reappraisal of the properties has now been tested long enough to confirm the worst fears of its critics. Unless its place is taken by some more promising scheme of rate control, the days of private ownership under government regulation may be numbered.' 2 Bonbright, Valuation of Property (1937) 1190.

***649** The prudent investment theory has relative merits in fixing rates for a utility which creates its service merely by its investment. The amount and quality of service rendered by the usual utility will, at least roughly, be measured by the amount of capital it puts into the enterprise. But it has no rational application where there is no such relationship between investment and capacity to serve. There is no such relationship between investment and amount of gas produced. Let us assume that Doe and Roe each produces in West Virginia for delivery to Cleveland the same quantity of natural gas per day. Doe, however, through luck or foresight or whatever it takes, gets his gas from investing $50,000 in leases and drilling. Roe drilled poorer territory, got smaller wells, and has invested $250,000. Does anybody imagine that Roe can get or ought to get for his gas five times as much as Doe because he has spent five times as much? The service one renders to society in the gas business is measured by what he gets out of the ground, not by what he puts into it, and there is little more relation between the investment and the results than in a game of poker.

Two-thirds of the gas Hope handles it buys from about 340 independent producers. It is obvious that the principle of rate-making applied to Hope's own gas cannot be applied, and has not been applied, to the bulk of the gas Hope delivers. It is not probable that the investment of any two of these producers will bear the same ratio to their investments. The gas, however, all goes to the same use, has the same utilization value and the same ultimate price.

To regulate such an enterprise by undiscriminatingly transplanting any body of rate doctrine conceived and ***650** adapted to the ordinary utility business can serve the 'public interest' as the Natural Gas Act requires, if at all, only by accident. Mr. Justice Brandeis, the pioneer juristic advocate of the prudent investment theory for man-made utilities, never, so far as I am able to discover, proposed its application to a natural gas case. On the other hand, dissenting in Commonwealth of Pennsylvania v. West Virginia, he reviewed the problems of gas supply and said, 'In no other field of public service regulation is the controlling body confronted with factors so baffling as in the natural gas industry, and in none is continuous supervision and control required in so high a degree.' 262 U.S. 553, 621, 43 S.Ct. 658, 674, 67 L.Ed. 1117, 32 A.L.R. 300. If natural gas rates are intelligently to be regulated we must fit our legal principles to the economy of the industry and not try to fit the industry to our books.

As our decisions stand the Commission was justified in believing that it was required to proceed by the rate base method even as to gas in the field. For this reason the Court may not merely wash its hands of the method and rationale of rate making. The fact is that this Court, with no discussion of its fitness, simply transferred the rate base method to the natural gas industry. It happened in Newark Natural Gas & Fuel Co. v. City of Newark, Ohio, 1917, 242 U.S. 405, 37 S.Ct. 156, 157, 61 L.Ed. 393, Ann.Cas.1917B, 1025, in which the company wanted 25 cents per m.c.f., and under the Fourteenth Amendment challenged the reduction to 18 cents by ordinance. This Court sustained the reduction because the court below 'gave careful consideration to the questions of the value of the property * * * at the time of the inquiry,' and whether the rate 'would be sufficient to provide a fair return on the value of the property.' The Court said this method was 'based upon principles thoroughly established by repeated secisions of this court,' citing many cases, not one of which involved natural gas or a comparable wasting natural resource. Then came issues as to state power to ***651** regulate as affected by the commerce clause. Public Utilities Commission v. Landon, 1919, 249 U.S. 236, 39 S.Ct. 268, 63 L.Ed. 577; Pennsylvania Gas Co. v. Public Service Commission, 1920, 252 U.S. 23, 40 S.Ct. 279, 64 L.Ed. 434. These questions settled, the Court again was called upon in natural gas cases to consider state rate-making claimed to be invalid under the Fourteenth Amendment. United Fuel Gas Co. v. Railroad Commission of Kentucky, 1929, 278 U.S. 300, 49 S.Ct. 150, 73 L.Ed. 390; United Fuel Gas Company v. Public Service Commission of West Virginia, 1929, 278 U.S. 322, 49 S.Ct. 157, 73 L.Ed. 402. Then, as now, the differences were 'due ****311** chiefly to the difference in value ascribed by each to the gas rights and leaseholds.' 278 U.S. 300, 311, 49 S.Ct. 150, 153, 73 L.Ed. 390. No one seems to have questioned that the rate base method must be pursued and the controversy was at what rate base must be used. Later the 'value' of gas in the field was questioned in determining the amount a regulated company should be allowed to pay an affiliate therefor-a state determination also reviewed under the Fourteenth Amendment. Dayton Power & Light Co. v. Public Utilities Commission of Ohio, 1934, 292 U.S. 290, 54 S.Ct. 647, 78 L.Ed. 1267; Columbus Gas & Fuel Co. v. Public Utilities Commission of Ohio, 1934, 292 U.S. 398, 54 S.Ct. 763, 78 L.Ed. 1327, 91 A.L.R. 1403. In both cases, one of which sustained, and one of which struck down a fixed rate the Court assumed the rate base method, as the legal way of testing reasonableness of natural gas prices fixed by public authority, without examining its real relevancy to the inquiry.

Under the weight of such precedents we cannot expect the Commission to initiate economically intelligent methods of fixing gas prices. But the Court now faces a new plan of federal regulation based on the power to fix the price at which gas shall be allowed to move in interstate commerce. I should now consider whether these rules devised under the Fourteenth Amendment are the exclusive tests of a just and reasonable rate under the federal statute, inviting reargument directed to that point ***652** if necessary. As I see it now I would be prepared to hold that these rules do not apply to a natural gas case arising under the Natural Gas Act.

Such a holding would leave the Commission to fix the price of gas in the field as one would fix maximum prices of oil or milk or coal, or any other commodity. Such a price is not calculated to produce a fair return on the synthetic value of a rate base of any individual producer, and would not undertake to assure a fair return to any producer. The emphasis would shift from the producer to the product, which would be regulated with an eye to average or typical producing conditions in the field.

Such a price fixing process on economic lines would offer little temptation to the judiciary to become back seat drivers of the price fixing machine. The unfortunate effect of judicial intervention in this field is to divert the attention of those engaged in the process from what is economically wise to what is legally permissible. It is probable that price reductions would reach economically unwise and self-defeating limits before they would reach constitutional ones. Any constitutional problems growing out of price fixing are quite different than those that have heretofore been considered to inhere in rate making. A producer would have difficulty showing the invalidity of such a fixed price so long as he voluntarily continued to sell his product in interstate commerce. Should he withdraw and other authority be invoked to compel him to part with his property, a different problem would be presented.

Allowance in a rate to compensate for gas removed from gas lands, whether fixed as of point of production or as of point of delivery, probably best can be measured by a functional test applied to the whole industry. For good or ill we depend upon private enterprise to exploit these natural resources for public consumption. The function which an allowance for gas in the field should perform ***653** for society in such circumstances is to be enough and no more than enough to induce private enterprise completely and efficiently to utilize gas resources, to acquire for public service any available gas or gas rights and to deliver gas at a rate and for uses which will be in the future as well as in the present public interest.

The Court fears that 'if we are now to tell the Commission to fix the rates so as to discourage particular uses, we would indeed be injecting into a rate case a 'novel' doctrine * * *.' With due deference I suggest that there is nothing novel in the idea that any change in price of a service or commodity reacts to encourage or discourage its use. The question is not whether such consequences will or will not follow; the question is whether effects must be suffered blindly or may be intelligently selected, whether price control shall have targets at which it deliberately aims or shall be handled like a gun in the hands of one who does not know it is loaded.

We should recognize 'price' for what it is-a tool, a means, an expedient. In public****312** hands it has much the same economic effects as in private hands. Hope knew that a concession in industrial price would tend to build up its volume of sales. It used price as an expedient to that end. The Commission makes another cut in that same price but the Court thinks we should ignore the effect that it will have on exhaustion of supply. The fact is that in natural gas regulation price must be used to reconcile the private property right society has permitted to vest in an important natural resource with the claims of society upon it-price must draw a balance between wealth and welfare.

To carry this into techniques of inquiry is the task of the Commissioner rather than of the judge, and it certainly is no task to be solved by mere bookkeeping but requires the best economic talent available. There would doubtless be inquiry into the price gas is bringing in the ***654** field, how far that price is established by arms' length bargaining and how far it may be influenced by agreements in restraint of trade or monopolistic influences. What must Hope really pay to get and to replace gas it delivers under this order? If it should get more or less than that for its own, how much and why? How far are such prices influenced by pipe line access to markets and if the consumers pay returns on the pipe lines how far should the increment they cause go to gas producers? East Ohio is itself a producer in Ohio. FN44 What do Ohio authorities require Ohio consumers to pay for gas in the field? Perhaps these are reasons why the Federal Government should put West Virginia gas at lower or at higher rates. If so what are they? Should East Ohio be required to exploit its half million acres of unoperated reserve in Ohio before West Virginia resources shall be supplied on a devalued basis of which that State complains and for which she threatens measures of self keep? What is gas worth in terms of other fuels it displaces?

FN44 East Ohio itself owns natural gas rights in 550,600 acres, 518,526 of which are reserved and 32,074 operated, by 375 wells. Moody's Manual of Public Utilities (1943) 5.

A price cannot be fixed without considering its effect on the production of gas. Is it an incentive to continue to exploit vast unoperated reserves? Is it conducive to deep drilling tests the result of which we may know only after trial? Will it induce bringing gas from afar to supplement or even to substitute for Appalachian gas? FN45 Can it be had from distant fields as cheap or cheaper? If so, that competitive potentiality is certainly a relevant consideration. Wise regulation must also consider, as a private buyer would, what alternatives the producer has ***655** if the price is not acceptable. Hope has intrastate business and domestic and industrial customers. What can it do by way of diverting its supply to intrastate sales? What can it do by way of disposing of its operated or reserve acreage to industrial concerns or other buyers? What can West Virginia do by way of conservation laws, severance or other taxation, if the regulated rate offends? It must be borne in mind that while West Virginia was prohibited from giving her own inhabitants a priority that discriminated against interstate commerce, we have never yet held that a good faith conservation act, applicable to her own, as well as to others, is not valid. In considering alternatives, it must be noted that federal regulation is very incomplete, expressly excluding regulation of 'production or gathering of natural gas,' and that the only present way to get the gas seems to be to call it forth by price inducements. It is plain that there is a downward economic limit on a safe and wise price.

FN45 Hope has asked a certificate of convenience and necessity to lay 1140 miles of 22-inch pipeline from Hugoton gas fields in southwest Kansas to West Virginia to carry 285 million cu. ft. of natural gas per day. The cost was estimated at $51,000,000. Moody's Manual of Public Utilities (1943) 1760.

But there is nothing in the law which compels a commission to fix a price at that 'value' which a company might give to its product by taking advantage of scarcity, or monopoly of supply. The very purpose of fixing maximum prices is to take away from the seller his opportunity to get all that otherwise the market would award him for his goods. This is a constitutional use of the power to fix maximum prices, ****313**Block v. Hirsh, 256 U.S. 135, 41 S.Ct. 458, 65 L.Ed. 865, 16 A.L.R. 165; Marcus Brown Holding Co. v. Feldman, 256 U.S. 170, 41 S.Ct. 465, 65 L.Ed. 877; International Harvester Co. v. Kentucky, 234 U.S. 216, 34 S.Ct. 853, 58 L.Ed. 1284; Highland v. Russell Car & Snow Plow Co., 279 U.S. 253, 49 S.Ct. 314, 73 L.Ed. 688, just as the fixing of minimum prices of goods in interstate commerce is constitutional although it takes away from the buyer the advantage in bargaining which market conditions would give him. United States v. Darby, 312 U.S. 100, 657, 61 S.Ct. 451, 85 L.Ed. 609, 132 A.L.R. 1430; Mulford v. Smith, 307 U.S. 38, 59 S.Ct. 648, 83 L.Ed. 1092; United States v. Rock Royal Co-operative, Inc., 307 U.S. 533, 59 S.Ct. 993, 83 L.Ed. 1446; Sunshine Anthracite Coal Co. v. Adkins, 310 U.S. 381, 60 S.Ct. 907, 84 L.Ed. 1263. The Commission has power to fix ***656** a price that will be both maximum and minimum and it has the incidental right, and I think the duty, to choose the economic consequences it will promote or retard in production and also more importantly in consumption, to which I now turn.

If we assume that the reduction in company revenues is warranted we then come to the question of translating the allowed return into rates for consumers or classes of consumers. Here the Commission fixed a single rate for all gas delivered irrespective of its use despite the fact that Hope has established what amounts to two rates-a high one for domestic use and a lower one for industrial contracts. FN46 The Commission can fix two prices for interstate gas as readily as one-a price for resale to domestic users and another for resale to industrial users. This is the pattern Hope itself has established in the very contracts over which the Commission is expressly given jurisdiction. Certainly the Act is broad enough to permit two prices to be fixed instead of one, if the concept of the 'public interest' is not unduly narrowed.

FN46 I find little information as to the rates for industries in the record and none at all in such usual sources as Moody's Manual.

The Commission's concept of the public interest in natural gas cases which is carried today into the Court's opinion was first announced in the opinion of the minority in the Pipeline case. It enumerated only two 'phases of the public interest: (1) the investor interest; (2) the consumer interest,' which it emphasized to the exclusion of all others. 315 U.S. 575, 606, 62 S.Ct. 736, 753, 86 L.Ed. 1037. This will do well enough in dealing with railroads or utilities supplying manufactured gas, electric, power, a communications service or transportation, where utilization of facilities does not impair their future usefulness. Limitation of supply, however, brings into a natural gas case another phase of the public interest that to my mind overrides both the owner ***657** and the consumer of that interest. Both producers and industrial consumers have served their immediate private interests at the expense of the long-range public interest. The public interest, of course, requires stopping unjust enrichment of the owner. But it also requires stopping unjust impoverishment of future generations. The public interest in the use by Hope's half million domestic consumers is quite a different one from the public interest in use by a baker's dozen of industries.

Prudent price fixing it seems to me must at the very threshold determine whether any part of an allowed return shall be permitted to be realized from sales of gas for resale for industrial use. Such use does tend to level out daily and seasonal peaks of domestic demand and to some extent permits a lower charge for domestic service. But is that a wise way of making gas cheaper when, in comparison with any substitute, gas is already a cheap fuel? The interstate sales contracts provide that at times when demand is so great that there is not enough gas to go around domestic users shall first be served. Should the operation of this preference await the day of actual shortage? Since the propriety of a preference seems conceded, should it not operate to prevent the coming of a shortage as well as to mitigate its effects? Should industrial use jeopardize tomorrow's service to householders any more than today's? If, however, it is decided to cheapen domestic use by resort to industrial sales, should they be limited to the few uses ****314** for which gas has special values or extend also to those who use it only because it is cheaper than competitive fuels? [FN47] And how much cheaper should industrial***658** gas sell than domestic gas, and how much advantage should it have over competitive fuels? If industrial gas is to contribute at all to lowering domestic rates, should it not be made to contribute the very maximum of which it is capable, that is, should not its price be the highest at which the desired volume of sales can be realized?

FN47 The Federal Power Commission has touched upon the problem of conservation in connection with an application for a certificate permitting construction of a 1500-mile pipeline from southern Texas to New York City and says: 'The Natural Gas Act as presently drafted does not enable the Commission to treat fully the serious implications of such a problem. The question should be raised as to whether the proposed use of natural gas would not result in displacing a less valuable fuel and create hardships in the industry already supplying the market, while at the same time rapidly depleting the country's natural-gas reserves. Although, for a period of perhaps 20 years, the natural gas could be so priced as to appear to offer an apparent saving in fuel costs, this would mean simply that social costs which must eventually be paid had been ignored.

'Careful study of the entire problem may lead to the conclusion that use of natural gas should be restricted by functions rather than by areas. Thus, it is especially adapted to space and water heating in urban homes and other buildings and to the various industrial heat processes which require concentration of heat, flexibility of control, and uniformity of results. Industrial uses to which it appears particularly adapted include the treating and annealing of metals, the operation of kilns in the ceramic, cement, and lime industries, the manufacture of glass in its various forms, and use as a raw material in the chemical industry. General use of natural gas under boilers for the production of steam is, however, under most circumstances of very questionable social economy.' Twentieth Annual Report of the Federal Power Commission (1940) 79.

If I were to answer I should say that the household rate should be the lowest that can be fixed under commercial conditions that will conserve the supply for that use. The lowest probable rate for that purpose is not likely to speed exhaustion much, for it still will be high enough to induce economy, and use for that purpose has more nearly reached the saturation point. On the other hand the demand for industrial gas at present rates already appears to be increasing. To lower further the industrial rate is merely further to subsidize industrial consumption and speed depletion. The impact of the flat reduction ***659** of rates ordered here admittedly will be to increase the industrial advantages of gas over competing fuels and to increase its use. I think this is not, and there is no finding by the Commission that it is, in the public interest.

There is no justification in this record for the present discrimination against domestic users of gas in favor of industrial users. It is one of the evils against which the Natural Gas Act was aimed by Congress and one of the evils complained of here by Cleveland and Akron. If

Hope's revenues should be cut by some $3,600,000 the whole reduction is owing to domestic users. If it be considered wise to raise part of Hope's revenues by industrial purpose sales, the utmost possible revenue should be raised from the least consumption of gas. If competitive relationships to other fuels will permit, the industrial price should be substantially advanced, not for the benefit of the Company, but the increased revenues from the advance should be applied to reduce domestic rates. For in my opinion the 'public interest' requires that the great volume of gas now being put to uneconomic industrial use should either be saved for its more important future domestic use or the present domestic user should have the full benefit of its exchange value in reducing his present rates.

Of course the Commission's power directly to regulate does not extend to the fixing of rates at which the local company shall sell to consumers. Nor is such power required to accomplish the purpose. As already pointed out, the very contract the Commission is altering classifies the gas according to the purposes for which it is to be resold and provides differentials between the two classifications. It would only be necessary for the Commission to order ****315** that all gas supplied under paragraph (a) of Hope's contract with the East Ohio Company shall be ***660** at a stated price fixed to give to domestic service the entire reduction herein and any further reductions that may prove possible by increasing industrial rates. It might further provide that gas delivered under paragraph (b) of the contract for industrial purposes to those industrial customers Hope has approved in writing shall be at such other figure as might be found consistent with the public interest as herein defined. It is too late in the day to contend that the authority of a regulatory commission does not extend to a consideration of public interests which it may not directly regulate and a conditioning of its orders for their protection. Interstate Commerce Commission v. Railway Labor Executives Ass'n, 315 U.S. 373, 62 S.Ct. 717, 86 L.Ed. 904; United States v. Lowden, 308 U.S. 225, 60 S.Ct. 248, 84 L.Ed. 208.

Whether the Commission will assert its apparently broad statutory authorization over prices and discriminations is, of course, its own affair, not ours. It is entitled to its own notion of the 'public interest' and its judgment of policy must prevail. However, where there is ground for thinking that views of this Court may have constrained the Commission to accept the rate-base method of decision and a particular single formula as 'all important' for a rate base, it is appropriate to make clear the reasons why I, at least, would not be so understood. The Commission is free to face up realistically to the nature and peculiarity of the resources in its control, to foster their duration in fixing price, and to consider future interests in addition to those of investors and present consumers. If we return this case it may accept or decline the proffered freedom. This problem presents the Commission an unprecedented opportunity if it will boldly make sound economic considerations, instead of legal and accounting theories, the foundation of federal policy. I would return the case to the Commission and thereby be clearly quit of what now may appear to be some responsibility for perpetrating a shortsighted pattern of natural gas regulation.

U.S. 1944.
Federal Power Commission v. Hope Natural Gas Co.
51 P.U.R.(NS) 193, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333

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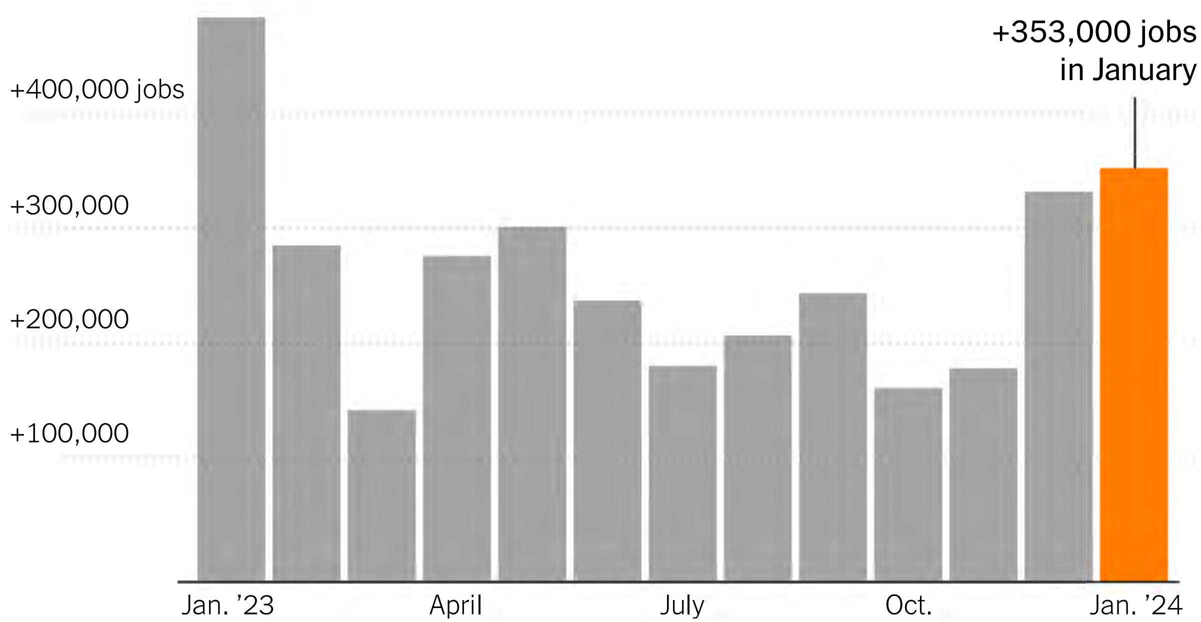
Job Market Starts 2024 With a Bang

U.S. employers added 353,000 jobs in January, far exceeding forecasts, and revised figures showed last year was even stronger than previously reported.

Monthly change in jobs



Note: Data is seasonally adjusted. • Source: Bureau of Labor Statistics • By Ella Koeze

By Lydia DePillis

Feb. 2, 2024

The United States produced an unexpectedly sizable batch of jobs last month, a boon for American workers that shows the labor market retains remarkable strength after three years of expansion.

Employers added 353,000 jobs in January on a seasonally adjusted basis, the Labor Department reported on Friday, and the unemployment rate remained at 3.7 percent.

The report also put an even shinier gloss on job growth for 2023, including revisions that added more than 100,000 to the figure previously tallied for December. All told, employers added 3.1 million jobs last year, more than the 2.7 million initially reported.

After the loss of 14 percent of the nation's jobs early in the Covid-19 pandemic, the labor market's endurance despite aggressive interest rate increases has caught economists off guard.

"I think everyone is surprised at the strength," said Sara Rutledge, an independent economics consultant. "It's almost like a 'pinch me' scenario."

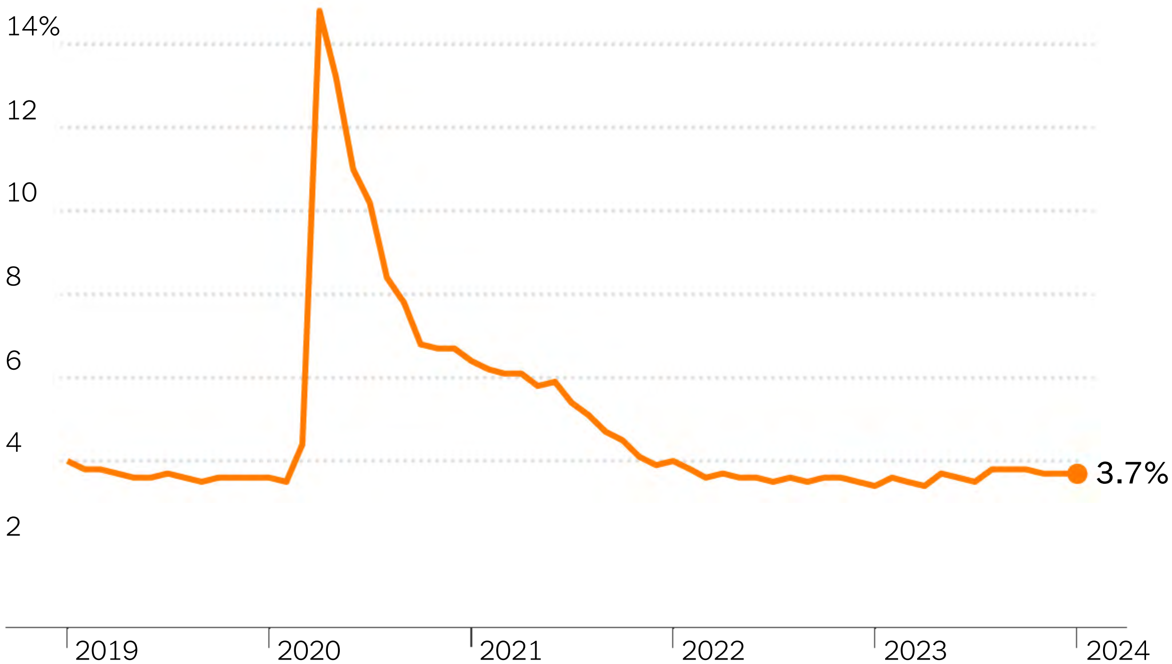
Ms. Rutledge helped tabulate the National Association for Business Economics' latest member survey, which found rising optimism that the country would avoid a recession — matching a turnaround in measures of consumer sentiment as inflation has eased.

January's crop of added jobs, nearly twice what forecasters had expected, mirrors the similarly surprising strength in gross domestic product measurements for the fourth quarter of 2023. It is also likely to reinforce the Federal Reserve's patient approach on interest rates, given the risk that increased wages might push prices up faster.

Jerome H. Powell, the Fed chair, signaled this week that rate cuts would not begin until at least May, citing a desire to see more evidence that inflation is falling back to its target.

Unemployment has been under 4 percent for 24 months

Unemployment rate



Note: Data is seasonally adjusted. • Source: Bureau of Labor Statistics • By Ella Koeze

The latest job data prompted a victory lap from Biden administration officials, who highlighted an unemployment rate only a few ticks above a 70-year low.

“The fact that that’s been below 4 percent for two years running now is just a very clear and reliable signal that this is not just a tight labor market, but a reliably and persistently tight labor market,” said Jared Bernstein, chair of the White House Council of Economic Advisers.

January's gains were also broader than has been the case in other recent reports: Professional and business services accelerated to pile on 74,000 jobs, while health care added 70,000. The only major sector to cut workers was mining and logging.

Average hourly earnings also grew swiftly, at 0.6 percent from December.

Still, analysts cautioned against reading too much into the month's overall gain, given recent volatility in initial survey estimates. Last January, for example, was much stronger than the full-year average. And the latest report contains a few oddities, as well.

The survey window was interrupted by bone-chilling cold and snowstorms, possibly shortening the workweek and raising hourly wages. Also, the addition of so many relatively well-paid white-collar workers may have pulled up the average. Hotels and restaurants, where pay is lower, shed a few thousand jobs.

Agron Nicaj, a U.S. economist at the banking and financial services firm MUFG, noted that job postings had been elevated in professional and business services for the past few months. That may mean January's surge will be short-lived, especially given the latest report from outplacement firm Challenger, Gray & Christmas that found layoff announcements surged last month after a quiet quarter.

"I wouldn't expect a reacceleration because of the relationship with the industries that grew this month and the openings," Mr. Nicaj said. "I think this month reflects a refilling of jobs that they couldn't fill."

Wage growth sped up in January

Year-over-year percentage change in earnings vs. inflation

Note: Earnings data is seasonally adjusted. • Source: Bureau of Labor Statistics • By Ella Koeze

And yet it's clear that the new year dawned on what has been an exceptionally good economy for many workers. Wages have been growing faster than their historical rates, and a strong increase in productivity over the last three quarters has helped keep those fatter paychecks from fueling higher prices. The number of open jobs still exceeds the stock of people looking for positions, even as new immigrants and women have joined or rejoined the work force in unexpected numbers.

That trend may continue if higher wages keep bringing people off the sidelines. The number of people not in the labor force who want a job has surged in recent months, to 5.8 million, suggesting that they could jump back in if pay outweighed the cost of child care or a long commute.

Over the past year, most gains have been powered by sectors that either took longer to recover from the pandemic — including hospitality and local governments — or have outsize momentum because of structural factors, such as aging demographics and pent-up demand for housing. Construction firms have kept hiring even in the face of high interest rates, because homeowners with low-rate mortgages are generally staying put, leaving new homes as the only option for would-be buyers.

The education and health sector leads in job gains

Change in jobs in January 2024, by sector

Education and health	+112,000 jobs
Business services	+74,000
Retail	+45,200
Government	+36,000
Manufacturing	+23,000
Leisure and hospitality	+11,000
Construction	+11,000

Note: Data is seasonally adjusted. • Source: Bureau of Labor Statistics • By Ella Koeze

Other categories that experienced supersize growth during 2021 and 2022, including transportation, warehousing and information technology, have been falling back to their prepandemic trends. Another handful of sectors, such as retail, have been largely flat.

One of those who jumped from a shrinking sector into a more stable one is Galvin Moore, 33, who worked in information technology for a freight broker until last fall, when he noticed the trucking sector contracting around him.

“It’s not just job security — it’s also the fear that you own career growth becomes limited by the industry,” said Mr. Moore, who is married with three children in a Houston suburb. He left for a position at an oil and gas services firm that is moving into technologies like geothermal energy and carbon capture. “They’re in growth mode, too,” Mr. Moore added, “It’s just a different phase of the cycle.”

The new gig also came with a 40 percent pay increase, which has allowed him to start paying down debt and think about buying a new house. “It’s like night and day,” Mr. Moore said.

Despite the prominent announcements of layoffs at companies like UPS, Google and Microsoft, most employers have been loath to part with workers, worried about being short-staffed if business picks up again. Although the share of workers quitting their jobs has fallen back to normal levels after a surge in 2022, Americans seem comfortable enough with their financial futures to keep spending money.

That has led to splurges on services like travel agencies, which saw their revenues sink almost to zero during the worst of the pandemic. While still a few thousand employees shy of 2019 levels, the American Society of Travel Advisors says the Bureau of Labor Statistics data does not reflect a surge of workers who have joined the industry as independent contractors, often working part time to supplement other jobs.

Kareem George, who runs a 10-person agency near Detroit that designs custom vacations, said his bookings were 20 percent above 2019 levels, with clients increasingly asking for luxury experiences like high-end dinners and private tours.

“I think there’s more confidence that they can plan longer term,” said Mr. George, who expects to hire two more people in the year ahead. “So they’re not thinking so much of, ‘I deserve it, I need to do it now,’ but also

'I can also think about next year and the year after.'"

In the coming months, economists had expected the labor market to become more like its prepandemic self, without the giant job growth that followed the pandemic lockdowns. The latest numbers may call that assessment into question.

Even manufacturing, which has been in a mild recession for about a year, added 23,000 positions. That reflects optimism in the latest purchasing managers index for manufacturing, which jumped unexpectedly last month. Timothy Fiore, the chair of the Institute for Supply Management committee that oversees the survey, said it seemed like the beginning of a turnaround, even if a slow one.

"Now we're starting to gain altitude," Mr. Fiore said. "It's not a fighter pilot gain; it's a cargo plane gain."

Jim Tankersley contributed reporting.

Lydia DePillis reports on the American economy. She has been a journalist since 2009, and can be reached at lydia.depillis@nytimes.com.
More about Lydia DePillis

A version of this article appears in print on , Section A, Page 1 of the New York edition with the headline: Labor Market Starts the Year With Big Gains

CME Group

FedWatch Tool

FED FUND FUTURES												
ZQG4	ZQH4	ZQJ4	ZQK4	ZQM4	ZQN4	ZQQ4	ZQU4	ZQV4	ZQX4	ZQZ4	ZQF5	ZQG5
94.6713	94.6725	94.6775	94.7275	94.8225	94.8800	95.0225	95.0975	95.2075	95.3125	95.4175	95.5250	95.6525

CME FEDWATCH TOOL - MEETING PROBABILITIES

MEETING DATE	325-350	350-375	375-400	400-425	425-450	450-475	475-500	500-525	525-550
3/20/2024				0.0%	0.0%	0.0%	0.0%	2.5%	97.5%
5/1/2024	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	23.0%	76.5%
6/12/2024	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	13.5%	53.8%	32.5%
7/31/2024	0.0%	0.0%	0.0%	0.0%	0.2%	8.1%	37.2%	41.2%	13.3%
9/18/2024	0.0%	0.0%	0.0%	0.1%	6.0%	29.6%	40.2%	20.6%	3.5%
11/7/2024	0.0%	0.0%	0.1%	3.3%	18.5%	35.2%	29.8%	11.5%	1.6%
12/18/2024	0.0%	0.0%	2.2%	13.7%	30.0%	31.5%	17.3%	4.7%	0.5%
1/29/2025	0.0%	1.3%	8.7%	22.9%	30.8%	23.5%	10.2%	2.4%	0.2%
3/12/2025	0.5%	3.9%	13.8%	25.7%	28.2%	18.7%	7.4%	1.6%	0.1%

CME FEDWATCH TOOL - TOTAL PROBABILITIES

MEETING DATE	DAYS TO MEETING	EASE	NO CHANGE	HIKE
3/20/2024	26	2.50 %	97.50 %	0.00 %
5/1/2024	68	23.52 %	76.48 %	0.00 %
6/12/2024	110	67.53 %	32.47 %	0.00 %
7/31/2024	159	86.65 %	13.35 %	0.00 %
9/18/2024	208	96.53 %	3.47 %	0.00 %
11/7/2024	258	98.37 %	1.63 %	0.00 %
12/18/2024	299	99.49 %	0.51 %	0.00 %
1/29/2025	341	99.78 %	0.22 %	0.00 %
3/12/2025	383	99.86 %	0.14 %	0.00 %

Blue Chip Financial Forecasts®

Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them

Vol. 43, No. 2, February 1, 2024

Wolters Kluwer

BLUE CHIP FINANCIAL FORECASTS®

Executive Editor: Joseph Aguinaldo
Assistant Editor: Jules Valencia
Haver Analytics
60 East 42nd Street
New York, NY 10165
Phone (212) 986-9300
E-mail: bluechip@haver.com

Robert J. Eggert, Founder
Randell E. Moore, Editor Emeritus
Rocco Impreveduto, General Manager

Blue Chip Financial Forecasts® (ISSN: 0741-8345) is published monthly by CCH Incorporated, 28 Liberty St., 44th Floor New York, NY 10005-1400. Printed in the U.S.A.

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Economic Surprises Continue

Full of surprises. The US economy surprised forecasters yet again in last year's fourth quarter with stronger-than-expected growth and lower-than-expected inflation. The last BCFF Q4 real GDP forecast (from the survey taken at the end of November) was for growth of 1.2% q/q saar. Just prior to the release on January 25, the market consensus expected a 2.0% increase. The actual figure was 3.3%. To be sure, some of the Q4 strength will likely be ephemeral, notably the increase in inventory investment. The inventory investment in Q4 was a little faster than needed to keep pace with trend demand growth. So, some slowdown ahead is likely.

However, demand was also solid in Q4. Personal consumption expenditures rose a solid 2.8% as continued robust labor market conditions boosted disposable income. Nonresidential investment, government spending and exports also made meaningful contributions in Q4. All in all, private domestic demand (final sales to private domestic purchasers) increased a respectable 2.6% q/q saar in Q4 2023 and 2.7% Q4/Q4.

Even as growth has remained above trend, inflation has continued to surprise on the downside. The GDP price index increased only 1.5% q/q saar in Q4, more than one percentage point below expectations. The PCE price index, the one on which the Fed places the most emphasis, increased just 1.7%, nearly one percentage point below expectations. The combination of above-trend growth and falling inflation has brightened the BCFF outlook considerably. In this month's survey, 81% of respondents think the US economy will achieve a "soft landing," that is a return of inflation to around the Fed's 2% target without the economy experiencing a recession, up markedly from 63% last month.

Expected slowdown. Still, the BCFF consensus expects much slower growth in 2024 than in 2023. It looks for real GDP growth to slow to 1.4% in Q1, and 0.9% in both Q2 and Q3. For the four quarters of 2024, the consensus looks for real GDP to advance just 1.2%, in stark contrast to the 3.1% increase in the four quarters of 2023 but up from 0.8% expected in last month's survey. Even though the consensus expects anemic growth throughout much of this year, it does not foresee a recession. The panel thinks there is only a 39% probability of a US recession occurring over the next 12 months versus 45% last month and a recent peak of 63% last February.

While the BCFF panel is not queried about the source of the expected slowdown, inferences can be made from the answers given to several special questions. First and foremost, the panel considers the current stance of monetary policy to be quite restrictive. The consensus estimate of the neutral fed funds rate (FFR) (the rate that is neither restrictive nor stimulative) is 2.86%, more than 250bps lower than the current FFR target of 5.375%, indicating a meaningfully tight policy. Furthermore, the panel accepts that changes in monetary policy impact the economy with a lag, with 80% thinking that the economy has yet to feel the full impact of previous tightening.

Less fiscal accommodation and weak growth abroad also appear to factor into the consensus US outlook. 93% of respondents think that accommodative fiscal policy played a key role in the resilience of the economy in 2023. 77% expect less accommodation this year with 52% thinking that the reduced fiscal boost will meaningfully slow the economy. Also, the consensus does not expect much help from abroad. The euro area economy contracted slightly in the second half of last year, and respondents place a 54% probability of a recession emerging within the next 12 months. The UK economy has also been struggling. Real GDP declined in the three months to November with respondents assigning a 56% probability of a recession ahead.

Fed prepares for rate cuts. The FOMC met at the end of January and as almost universally expected, left its FFR target unchanged at 5.375%, where it has been since last July. In the announcement following the meeting, it moved to a more neutral position concerning the likely direction of future policy actions and noted explicitly that it would keep policy sufficiently restrictive until the committee is confident that inflation is on a path to the 2% target. Message to financial markets: the next move in the FFR will be down but it might not occur as soon as you expect. With the Fed expected to reduce the FFR, economic growth expected to slow, and inflation anticipated to remain near target, the BCFF consensus expects market interest rates across all maturities to decline throughout the six-quarter forecast horizon.

BCFF panelists were queried about several aspects of the near-term course for monetary policy. First was the timing of the first FFR cut. A plurality of respondents (41%) looks for the first cut to occur at the May FOMC meeting with 16% expecting one in March and 25% anticipating the first cut in June. All respondents except one expect the first cut to have occurred by July. On average, the group anticipates the FFR target to be reduced by 112bps during 2024. This stands in contrast to the FOMC which expects only 75bps of rate cuts this year. And while the fed funds futures market has recently priced out some of the rate cuts it had previously priced in, it still envisages a much larger 125bps of FFR cuts in 2024.

What about QT? A component of the recent tightening of monetary policy that has received less attention is the decline in the Fed's security holdings on its balance sheet. In support of its tightening of monetary policy via increases in the FFR target that began in March 2022, the Fed has also been allowing its security holdings to decline since June 2022 at a pace of $80 billion per month. This is known as quantitative tightening (QT) as it reduces the reserves held by the banking system. Since June 2022, the Fed's security holdings have declined by more than $1.3 trillion but are still more than 80% larger than they were prior to the pandemic. A question that has arisen in financial markets as they anticipate the first FFR cut is whether the Fed would stop the reduction in its balance sheet when it began to cut the FFR. BCFF panelists mostly think it won't, with only 23% expecting that QT will be halted when the Fed begins to lower interest rates.

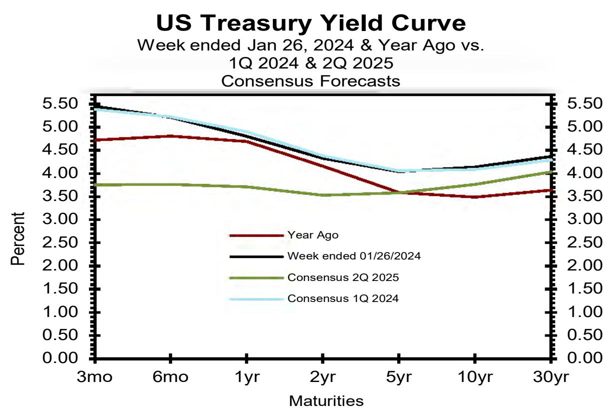
Sandy Batten (Haver Analytics, New York, NY)

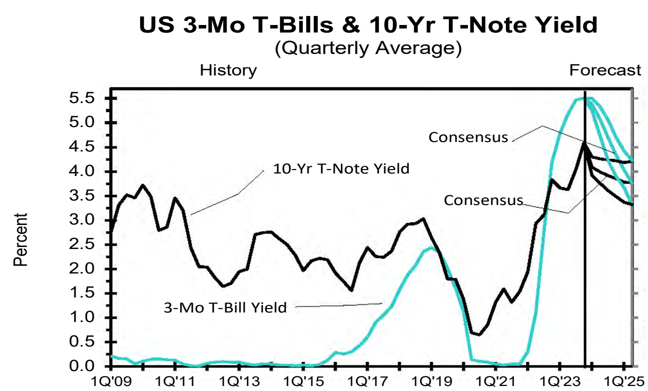
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

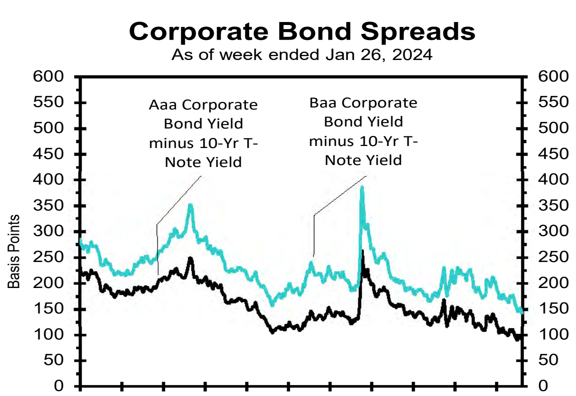
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	1Q	2Q	3Q	4Q	1Q	2Q
Interest Rates	Jan 26	Jan 19	Jan 12	Jan 6	Dec	Nov	Oct	4Q 2023	**2024**	**2024**	**2024**	**2024**	**2025**	**2025**
Federal Funds Rate	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.33	**5.3**	**5.1**	**4.7**	**4.4**	**4.1**	**3.8**
Prime Rate	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	**8.5**	**8.2**	**7.9**	**7.6**	**7.3**	**7.0**
SOFR	5.31	5.31	5.31	5.36	5.33	5.32	5.31	5.32	**5.3**	**5.2**	**4.8**	**4.5**	**4.2**	**3.9**
Commercial Paper, 1-mo.	5.32	5.33	5.32	5.32	5.32	5.33	5.33	5.33	**5.3**	**5.1**	**4.7**	**4.4**	**4.1**	**3.9**
Treasury bill, 3-mo.	5.45	5.46	5.47	5.47	5.44	5.52	5.60	5.52	**5.4**	**5.1**	**4.7**	**4.3**	**4.0**	**3.8**
Treasury bill, 6-mo.	5.21	5.20	5.22	5.25	5.34	5.44	5.57	5.45	**5.2**	**5.0**	**4.6**	**4.3**	**4.0**	**3.8**
Treasury bill, 1 yr.	4.80	4.79	4.77	4.83	4.96	5.28	5.42	5.22	**4.9**	**4.7**	**4.4**	**4.1**	**3.9**	**3.7**
Treasury note, 2 yr.	4.33	4.32	4.30	4.36	4.46	4.88	5.07	4.80	**4.4**	**4.2**	**4.0**	**3.8**	**3.7**	**3.5**
Treasury note, 5 yr.	4.04	4.02	3.93	3.96	4.00	4.49	4.77	4.42	**4.1**	**3.9**	**3.8**	**3.7**	**3.6**	**3.6**
Treasury note, 10 yr.	4.14	4.12	4.00	3.98	4.02	4.50	4.80	4.44	**4.1**	**4.0**	**3.9**	**3.9**	**3.8**	**3.8**
Treasury note, 30 yr.	4.37	4.34	4.19	4.12	4.14	4.66	4.95	4.58	**4.3**	**4.2**	**4.2**	**4.1**	**4.0**	**4.0**
Corporate Aaa bond	5.07	5.04	4.98	4.97	4.95	5.52	5.87	5.45	**5.0**	**5.0**	**4.9**	**4.9**	**4.8**	**4.8**
Corporate Baa bond	5.57	5.55	5.50	5.51	5.51	6.15	6.53	6.07	**6.0**	**6.0**	**5.9**	**5.9**	**5.8**	**5.8**
State & Local bonds	4.17	4.10	4.05	4.03	4.13	4.56	4.88	4.52	**4.3**	**4.3**	**4.2**	**4.2**	**4.1**	**4.1**
Home mortgage rate	6.69	6.60	6.66	6.62	6.82	7.44	7.62	7.29	**6.7**	**6.6**	**6.5**	**6.3**	**6.2**	**6.1**

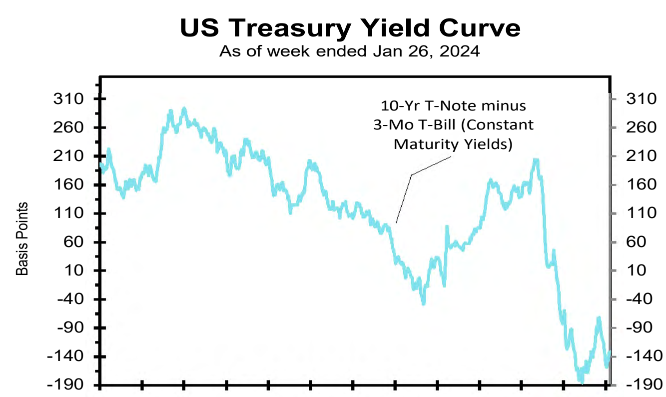
	History								Consensus Forecasts-Quarterly					
	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	**1Q**	**2Q**	**3Q**	**4Q**	**1Q**	**2Q**
Key Assumptions	2022	2022	2022	2022	2023	2023	2023	2023	**2024**	**2024**	**2024**	**2024**	**2025**	**2025**
Fed's AFE $ Index	108.3	113.5	118.8	119.8	115.5	114.6	115.0	116.6	**115.2**	**114.9**	**114.7**	**114.5**	**114.7**	**114.6**
Real GDP	-2.0	-0.6	2.7	2.6	2.2	2.1	4.9	3.3	**1.4**	**0.9**	**0.9**	**1.4**	**1.8**	**2.0**
GDP Price Index	8.5	9.1	4.4	3.9	3.9	1.7	3.3	1.5	**2.2**	**2.2**	**2.3**	**2.2**	**2.2**	**2.1**
Consumer Price Index	9.2	9.7	5.5	4.2	3.8	2.7	3.6	2.8	**2.5**	**2.4**	**2.4**	**2.3**	**2.2**	**2.2**
PCE Price Index	7.7	7.2	4.7	4.1	4.2	2.5	2.6	1.7	**2.2**	**2.3**	**2.2**	**2.2**	**2.1**	**2.1**

Forecasts for interest rates and the Federal Reserve's Advanced Foreign Economies Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, CPI and PCE Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP, GDP Price Index and PCE Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index history is from the Department of Labor's Bureau of Labor Statistics (BLS).









Policy Rates[1]

	History: Latest:	Month Ago:	Year Ago:	Consensus Forecasts Months From Now: 3	6	12
U.S.	5.38	5.38	4.38	**5.31**	**4.95**	**4.24**
Japan	-0.10	-0.10	-0.10	**-0.07**	**0.03**	**0.04**
U.K.	5.25	5.25	3.50	**5.17**	**4.93**	**4.27**
Switzerland	1.75	1.75	1.00	**1.71**	**1.63**	**1.41**
Canada	5.00	5.00	4.50	**4.96**	**4.56**	**3.83**
Australia	4.35	4.35	3.10	**4.36**	**4.21**	**3.71**
Euro area	4.50	4.50	2.50	**4.33**	**4.05**	**3.38**

10-Yr. Government Bond Yields[2]

	History: Latest:	Month Ago:	Year Ago:	Consensus Forecasts Months From Now: 3	6	12
U.S.	4.15	3.88	3.52	**4.02**	**3.92**	**3.89**
Germany	2.30	2.03	2.23	**2.35**	**2.29**	**2.24**
Japan	0.72	0.65	0.50	**0.75**	**0.82**	**0.95**
U.K.	4.06	3.62	3.46	**3.89**	**3.81**	**3.81**
France	2.78	2.56	2.70	**2.82**	**2.75**	**2.70**
Italy	3.83	3.69	4.23	**4.00**	**3.97**	**3.92**
Switzerland	0.87	0.66	1.23	**1.03**	**1.10**	**1.37**
Canada	3.52	3.11	2.89	**3.41**	**3.36**	**3.33**
Australia	4.19	3.96	3.54	**4.51**	**4.28**	**4.21**
Spain	3.25	2.88	3.19	**3.27**	**3.22**	**3.19**

Foreign Exchange Rates[3]

	History: Latest:	Month Ago:	Year Ago:	Consensus Forecasts Months From Now: 3	6	12
U.S.	115.23	112.81	113.82	**113.9**	**113.3**	**113.4**
Japan	147.94	140.92	129.94	**145.4**	**140.7**	**135.8**
U.K.	1.27	1.27	1.24	**1.26**	**1.27**	**1.27**
Switzerland	0.86	0.84	0.92	**0.87**	**0.87**	**0.86**
Canada	1.35	1.32	1.33	**1.34**	**1.33**	**1.30**
Australia	0.66	0.68	0.71	**0.66**	**0.67**	**0.69**
Euro	1.09	1.11	1.09	**1.09**	**1.10**	**1.12**

Consensus Policy Rates vs. US Rate

	Now	In 12 Mo.
Japan	-5.48	**-4.19**
U.K.	-0.13	**0.04**
Switzerland	-3.63	**-2.82**
Canada	-0.38	**-0.41**
Australia	-1.03	**-0.52**
Euro area	-0.88	**-0.86**

Consensus 10-Year Gov't Yields vs. U.S. Yield

	Now	In 12 Mo.
Germany	-1.85	**-1.64**
Japan	-3.43	**-2.94**
U.K.	-0.09	**-0.08**
France	-1.37	**-1.19**
Italy	-0.32	**0.04**
Switzerland	-3.28	**-2.52**
Canada	-0.63	**-0.56**
Australia	0.04	**0.32**
Spain	-0.90	**-0.69**

Forecasts of panel members are on pages 10 and 11. Definitions of variables are as follows: [1]Monetary policy rates. [2]Government bonds are yields to maturity. [3]Foreign exchange rate forecasts for U.K., Australia and the Euro are U.S. dollars per currency unit. For the U.S dollar, forecasts are of the U.S. Federal Reserve Board's AFE Dollar Index.

International. Global bond yields have generally been climbing in the early weeks of this year as investors have been re-evaluating the scope for central banks to swiftly pivot toward looser monetary policy. This reassessment has, in turn, been reinforced by some hawkish remarks from some policymakers coupled with evidence suggesting that US and European labor markets remain tight. In the meantime, escalating tensions in the Middle East have also been choking off key shipping routes and raising concerns about the resilience of global supply chains. Despite these setbacks, global equity markets have recovered some poise in recent days and, on the whole, remain resilient. This can partly be traced to some stronger-than-expected US growth data and upbeat news on the corporate earnings front, particularly from the technology sector

How central banks now respond to these crosscurrents remains to be seen. The recent disruption of Red Sea shipping routes has arguably shifted global growth risks to the downside. It was certainly of note that January's flash PMI data showed that manufacturers are now reporting growing issues with supply chains. Across the four largest developed economies, the US, Euro area, Japan and the UK, average supplier delivery times lengthened in January for the first time in 12 months. Still, some economies were more affected than others. The UK, for example, was worst hit, with lead times lengthening to a degree not seen since September 2022. But longer deliveries were also reported in the US, Euro area and Japan. It was notable too, however, in these surveys that this lengthening of supplier lead times was accompanied by a broadly-based rise in manufacturers' input costs.

Against that backdrop, the responses to one of our special questions this month reveals heightened optimism among our panelists about the US economic outlook, presumably, in part, due to stronger-than-expected growth momentum in Q4 2023. Specifically, our panelists now assign only a 39% probability to the likelihood of a US recession within the next 12 months, a decrease from 45% in last month's survey. However, this optimism contrasts with persistent pessimism about the European economic outlook. The probability of a recession in the Euro area is specifically placed at 54%, and 56% for the UK, with both figures little changed from last month's survey.

Our panelists' forecasts for the calibration of monetary policy in the Euro area and UK are also little-changed compared with last month with their respective policy rates expected to decline modestly within the next 3 to 6 months. When specifically asked about the timing of rate cuts by central banks, 9% of our panelists foresee the ECB starting to reduce rates in Q1 2024, 61% predict a cut in Q2, and 26% in Q3. Regarding the BoE, 4% of our panelists expect a rate cut in Q1, while 39% anticipate a move in Q2, and 48% anticipate Q3.

As for the BoJ, our panelists continue to expect a monetary policy normalization phase to proceed in the coming months. But there is now a little more unanimity about when exactly this process will commence. For example, in this month's survey 57% of panelists expect a first policy rate hike from the BoJ in Q2 2024. That contrasts with just 5% expecting a hike in Q1, a further 14% expecting a hike in Q3 with a further 24% opting for Q4 or later. These expectations also differ from last month's survey, where 16% predicted a Q1 hike, 37% a Q2 hike, 16% a Q3 hike, and 31% a hike in Q4 or later. The emerging consensus for a first rate hike in Q2 2024 could be influenced by the BoJ's recent statements emphasizing the upcoming Spring wage negotiations and the general importance of wage inflation in shaping monetary policy.

Finally, amid much uncertainty about China's economic prospects, the PBoC has recently announced that it will cut the reserve requirement ratio (RRR) for banks by 50 bps, effective February 5. Whether this latest easing initiative can alleviate the challenges China currently faces is open to much debate, however, not least given the structural roots of its many economic problems.

First Quarter 2024

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	1 Federal Funds Rate	2 Prime Bank Rate	3 SOFR Rate	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Avg. For ---Qtr.--- Fed's Adv Fgn Econ $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index	E. PCE Price Index
	-----Percent Per Annum -- Average For Quarter-----																------(Q-Q % Change)------			
	------Short-Term------							---Intermediate-Term---			------Long-Term------						------(SAAR)------			
J.P. Morgan Chase	5.5 H	na	na	na	na	na	na	4.4	3.9	3.9	4.1	na	na	na	na	na	1.8	1.9	2.1	1.8
Scotiabank Group	5.5 H	na	5.3	na	5.4	na	na	4.1 L	3.9	3.8 L	4.1	na	na	na	na	na	0.5	1.1 L	3.0	2.8
Chmura Economics & Analytics	5.4	8.5 H	5.4	5.3	5.5	5.3	4.8	4.4	4.0	4.1	4.2	5.0	na	na	6.7	na	1.8	3.3	3.3 H	3.1
EY-Parthenon	5.4	na	na	na	5.3	na	na	na	na	4.1	na	na	na	na	na	na	1.7	2.0	2.4	2.3
Fannie Mae	5.4	8.5 H	na	na	5.3	5.0 L	4.7	4.3	4.0	4.1	4.3	na	na	na	6.6	na	0.9	1.6	2.0	1.5
ING	5.4	na	na	na	na	na	na	4.4	4.0	4.0	4.2	na	na	na	na	na	1.8	na	na	na
KPMG	5.4	8.5 H	5.4	5.3	5.5	5.4	4.9	4.3	3.8 L	3.8 L	4.0 L	4.7	5.8	na	6.7	na	1.3	1.4	2.4	1.5
Naroff Economics LLC	5.4	8.4	5.3	5.2	5.4	5.2	4.8	4.4	4.0	4.1	4.3	5.0	5.5 L	4.1	6.6	115.1	0.5	3.2	3.3 H	3.0
Nomura Securities, Inc.	5.4	8.5 H	na	na	na	na	na	4.3	4.1	4.2	na	na	na	na	na	na	2.4	1.3	2.5	1.7
Oxford Economics	5.4	8.5 H	5.4	na	5.4	5.3	4.9	4.4	4.1	4.1	4.3	4.4 L	na	na	6.9	114.1	1.9	2.0	1.8 L	1.8
Roberts Capital Advisors	5.4	8.5 H	5.4	5.4 H	5.4	5.4	5.3	4.8	4.6 H	4.6 H	4.7 H	5.5	6.5	4.8	7.0	116.0	2.1	2.5	2.8	2.5
The Lonski Group	5.4	8.5 H	5.3	5.4 H	5.4	5.1	4.7	4.3	3.9	4.0	4.2	5.2	5.7	4.2	6.6	115.5	0.7	2.1	2.0	1.8
The Northern Trust Company	5.4	8.5 H	5.3	5.4 H	5.5	5.4	5.2	4.4	4.2	4.1	4.4	5.0	6.0	4.3	7.0	116.0	1.1	2.3	2.8	2.6
Action Economics	5.3	8.5 H	5.7 H	5.3	5.4	5.3	5.0	4.5	4.2	4.2	4.3	4.8	5.8	4.3	7.3 H	117.3 H	1.8	1.7	2.2	1.4 L
BMO Capital Markets	5.3	8.5 H	5.3	5.4 H	5.4	5.2	4.8	4.3	4.0	4.0	4.3	4.9	5.9	4.2	6.6	114.9	1.5	2.0	3.0	2.3
Comerica Bank	5.3	8.5 H	5.3	na	5.3	5.2	4.7	4.2	3.9	4.0	4.1	4.7	5.6	na	6.5	na	1.0	3.5 H	2.7	3.3 H
Daiwa Capital Markets America	5.3	8.5 H	5.3	na	5.3	na	na	4.3	3.9	4.0	4.2	na	na	na	6.5	116.0	1.2	2.2	2.6	2.6
DePrince & Assoc.	5.3	8.5 H	5.3	5.4 H	5.5	5.2	4.8	4.3	3.9	4.0	4.2	4.9	5.7	4.0	6.6	115.6	1.2	2.6	2.7	2.5
Economist Intelligence Unit	5.3	8.3	na	5.3	5.5	5.3	4.9	4.3	4.0	4.2	4.3	na	na	na	6.7	na	0.9	na	2.1	na
Georgia State University	5.3	8.4	na	na	5.4	5.2	4.8	4.2	4.0	4.0	4.3	4.7	5.9	na	6.9	na	0.4 L	2.3	2.2	2.4
GLC Financial Economics	5.3	8.4	5.3	5.3	5.4	5.3	5.3	5.0 H	4.6 H	4.3	4.4	5.2	6.2	4.4	7.0	115.5	0.9	2.4	2.4	2.2
Loomis, Sayles & Company	5.3	8.5 H	5.3	5.3	5.5	5.4	5.0	4.3	4.0	4.1	4.3	4.9	5.9	4.1	6.8	115.2	1.5	1.5	2.6	1.5
MacroFin Analytics & Rutgers Bus School	5.3	8.5 H	5.3	5.3	5.4	5.2	4.8	4.3	4.0	4.1	4.4	5.0	5.8	4.1	6.7	115.3	1.1	2.6	2.8	2.6
Moody's Analytics	5.3	8.5 H	5.3	5.4 H	5.2	5.1	5.0	4.8	4.5	4.2	4.6	5.2	6.1	4.0	7.1	na	1.5	2.5	2.5	2.3
NatWest Markets	5.3	8.5 H	na	5.4 H	5.6 H	5.7 H	5.8 H	4.5	4.3	4.4	4.7 H	5.7 H	6.6 H	5.1 H	6.9	na	2.0	1.7	2.5	2.2
PNC Financial Services Corp.	5.3	8.5 H	5.4	na	5.3	5.3	4.8	4.4	4.0	4.0	4.1	na	5.9	3.9	6.6	117.0	0.7	2.3	2.1	1.8
Regions Financial Corporation	5.3	8.3	5.3	5.4 H	5.4	5.2	4.8	4.3	4.0	4.1	4.3	5.1	6.1	4.4	6.7	114.9	1.8	2.1	2.0	1.6
S&P Global Market Intelligence	5.3	8.4	5.3	na	5.3	5.1	4.8	4.2	3.8 L	3.8 L	4.0 L	na	na	na	6.6	na	1.2	1.4	2.4	1.5
Santander Capital Markets	5.3	8.5 H	5.3	5.3	5.4	5.2	4.9	4.4	4.1	4.2	4.4	5.0	5.8	3.5 L	6.7	115.5	1.6	3.0	2.8	2.1
Societe Generale	5.3	8.5 H	5.3	na	5.3	5.1	4.6 L	4.2	4.0	4.0	4.2	na	na	na	na	na	0.4 L	1.8	2.2	2.2
TS Lombard	5.3	8.4	5.3	5.3	5.2	5.3	4.8	4.3	3.9	4.0	4.1	4.9	5.7	4.0	5.8 L	110.0 L	1.0	2.5	2.5	2.5
Via Nova Investment Mgt.	5.3	8.5 H	5.3	5.3	5.5	5.3	4.8	4.3	4.0	4.1	4.4	5.2	5.9	4.1	6.9	114.8	2.5	2.1	2.1	2.1
Bank of America	5.1 L	na	na	na	na	na	na	4.8	4.5	4.4	4.7 H	na	na	na	na	na	1.0	2.7	2.2	2.0
Barclays	5.1 L	na	na	na	na	na	na	4.3	4.1	4.3	4.5	na	na	na	na	na	2.0	2.0	2.5	1.6
Chan Economics	5.1 L	8.1 L	5.0 L	5.0 L	5.1 L	5.2	5.0	4.5	4.0	4.1	4.3	5.3	6.3	4.7	6.9	114.0	2.5	2.2	2.4	2.1
Goldman Sachs & Co.	5.1 L	na	na	na	5.5	na	na	4.2	3.8 L	3.9	4.1	na	na	na	na	na	2.8 H	2.2	2.8	2.1
Wells Fargo	5.1 L	8.5 H	5.4	5.1	5.2	5.0 L	4.6 L	4.3	4.0	4.0	4.2	5.2	6.2	4.6	6.8	na	1.4	2.0	2.5	2.0
February Consensus	**5.3**	**8.5**	**5.3**	**5.3**	**5.4**	**5.2**	**4.9**	**4.4**	**4.1**	**4.1**	**4.3**	**5.0**	**6.0**	**4.3**	**6.7**	**115.2**	**1.4**	**2.2**	**2.5**	**2.2**
Top 10 Avg.	5.4	8.5	5.4	5.4	5.5	5.4	5.1	4.6	4.3	4.3	4.5	5.3	6.2	4.5	7.0	116.0	2.2	2.8	2.9	2.8
Bottom 10 Avg.	5.2	8.4	5.3	5.2	5.3	5.1	4.7	4.2	3.9	3.9	4.1	4.8	5.7	4.0	6.5	114.4	0.7	1.5	2.1	1.6
January Consensus	5.3	8.4	5.3	5.3	5.4	5.3	5.0	4.5	4.2	4.2	4.3	5.1	6.1	4.3	6.9	115.2	0.9	2.3	2.4	2.2
Number of Forecasts Changed From A Month Ago:																				
Down	8	2	2	4	4	15	17	17	17	18	18	9	11	8	19	6	3	21	12	18
Same	27	26	19	14	21	12	8	15	13	11	8	8	6	6	6	7	6	10	11	9
Up	2	2	4	3	7	1	3	4	6	8	9	5	4	4	3	5	28	4	13	8
Diffusion Index	42%	50%	54%	48%	55%	25%	25%	32%	35%	36%	37%	41%	33%	39%	21%	47%	84%	26%	51%	36%

Second Quarter 2024

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term			Long-Term					Avg. For Qtr.	(Q-Q % Change) (SAAR)			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	A.	B.	C.	D.	E.
	Federal Funds Rate	Prime Bank Rate	SOFR Rate	Com. Paper 1-Mo.	Treas. Bills 3-Mo.	Treas. Bills 6-Mo.	Treas. Bills 1-Yr.	Treas. Notes 2-Yr.	Treas. Notes 5-Yr.	Treas. Notes 10-Yr.	Treas. Bond 30-Yr.	Aaa Corp. Bond	Baa Corp. Bond	State & Local Bonds	Home Mtg. Rate	Fed's Adv Fgn Econ $ Index	Real GDP	GDP Price Index	Cons. Price Index	PCE Price Index
Chmura Economics & Analytics	5.4 H	8.5 H	5.4	5.4 H	5.3	5.3 H	5.0	4.5	4.1	4.2	4.3	5.1	na	na	6.7	na	-0.2	3.0	3.0 H	2.9 H
J.P. Morgan Chase	5.4 H	na	na	na	na	na	na	4.2	3.8	3.9	4.2	na	na	na	na	na	0.5	2.0	2.2	1.9
Action Economics	5.3	8.4	5.8 H	5.3	5.2	5.1	4.8	4.4	4.2	4.2	4.3	4.8	5.8	4.3	7.3 H	116.5	1.9	1.4	2.3	1.7
BMO Capital Markets	5.3	8.5 H	5.3	5.4 H	5.4 H	5.2	4.7	4.1	4.0	3.9	4.2	4.8	5.8	4.2	6.5	114.3	0.8	2.6	2.6	2.5
Comerica Bank	5.3	8.5 H	5.3	na	5.2	5.0	4.5	3.9	3.6	3.7	3.9	4.6	5.5 L	na	6.1	na	1.0	3.3 H	2.4	2.4
Daiwa Capital Markets America	5.3	8.4	5.2	na	4.9	na	na	4.1	3.7	3.9	4.2	na	na	na	6.3	116.0	-0.1	2.5	2.4	2.3
MacroFin Analytics & Rutgers Bus School	5.3	8.5 H	5.3	5.3	5.2	5.2	4.7	4.3	3.8	3.9	4.0	5.0	5.8	4.0	6.8	115.1	1.0	2.3	2.5	2.5
Naroff Economics LLC	5.3	8.4	5.2	5.2	5.2	5.0	4.8	4.3	3.9	4.0	4.3	5.0	5.5 L	4.1	6.5	114.7	2.1	2.8	3.0 H	2.8
PNC Financial Services Corp.	5.3	8.5 H	5.3	na	5.2	5.1	4.8	4.3	4.0	4.0	4.2	na	6.6 H	4.9 H	6.6	117.8 H	0.0	1.8	1.5 L	1.4 L
Roberts Capital Advisors	5.3	8.4	5.3	5.3	5.3	5.2	5.0	4.6	4.4 H	4.4 H	4.6	5.4	6.4	4.7	6.7	115.5	2.2	2.5	2.5	2.4
Santander Capital Markets	5.3	8.5 H	5.3	5.3	5.4 H	5.2	4.9	4.6	4.3	4.3	4.5	5.2	6.1	3.7 L	6.8	115.0	1.5	2.8	2.9	2.6
Scotiabank Group	5.3	na	5.1	na	5.0	na	na	3.7	3.8	3.7	4.0	na	na	na	na	na	0.1	0.5 L	2.8	2.6
The Lonski Group	5.3	8.5 H	5.3	5.4 H	5.4 H	5.0	4.6	4.3	3.9	3.9	4.1	5.1	5.8	4.2	6.4	116.1	0.6	2.2	2.3	2.0
The Northern Trust Company	5.3	8.4	5.2	5.4 H	5.3	5.2	5.0	4.3	4.3	4.3	4.6	5.3	6.4	4.6	7.1	115.0	1.0	2.3	2.5	2.4
DePrince & Assoc.	5.2	8.3	5.1	5.2	5.3	5.1	4.7	4.2	3.8	4.0	4.2	5.0	5.8	4.1	6.4	116.2	1.4	2.6	2.6	2.5
Economist Intelligence Unit	5.2	8.2	na	5.2	5.3	5.2	4.8	4.3	4.0	4.1	4.1	na	na	na	6.6	na	0.7	na	2.2	na
Fannie Mae	5.2	8.3	na	na	4.7	4.6	4.3	4.1	4.0	4.1	4.4	na	na	na	6.5	na	0.7	2.3	2.8	2.5
KPMG	5.2	8.3	5.2	5.0	5.2	5.1	4.6	4.1	3.7	3.7	3.9	4.5	5.6	na	6.4	na	0.9	2.2	2.9	2.5
Oxford Economics	5.2	8.3	5.2	na	5.2	5.1	4.6	4.2	3.8	3.9	4.2	4.2 L	na	na	6.8	114.6	1.3	2.1	2.2	2.0
EY-Parthenon	5.1	na	na	na	5.0	na	na	na	na	3.9	na	na	na	na	na	na	1.0	2.2	1.9	2.1
GLC Financial Economics	5.1	8.2	5.1	5.1	5.1	5.0	5.1 H	4.7 H	4.3	4.1	4.4	5.1	6.1	4.4	6.8	114.9	0.6	2.4	2.4	2.2
Loomis, Sayles & Company	5.1	8.3	5.1	5.1	5.3	5.2	4.8	4.0	3.9	4.0	4.2	4.8	5.8	4.0	6.7	114.5	1.0	2.0	2.9	2.1
Moody's Analytics	5.1	8.3	5.1	5.1	4.9	4.9	4.8	4.6	4.4 H	4.2	4.6	5.5 H	6.4	4.2	6.9	na	1.3	2.0	2.8	2.3
Nomura Securities, Inc.	5.1	8.3	na	na	na	na	na	4.2	4.0	4.1	na	na	na	na	na	na	1.7	1.6	2.0	2.1
S&P Global Market Intelligence	5.1	8.2	5.1	na	4.9	4.7	4.4	3.9	3.6	3.7	3.9	na	na	na	6.4	na	1.1	2.2	2.8	2.4
Societe Generale	5.1	8.3	5.1	na	4.9	4.6	4.1 L	3.7	3.8	3.8	4.0	na	na	na	na	na	-1.4 L	1.8	2.2	2.6
Regions Financial Corporation	5.0	8.0	5.0	5.1	5.2	5.0	4.6	4.1	3.9	4.1	4.3	5.1	6.1	4.3	6.6	114.6	1.7	2.6	2.3	2.4
Via Nova Investment Mgt.	5.0	8.3	5.1	5.1	5.0	5.0	5.0	4.0	3.9	3.9	4.1	5.0	5.7	3.9	6.7	114.0	2.5 H	2.1	2.1	2.1
Bank of America	4.9	na	na	na	na	na	na	4.5	4.4 H	4.3	4.7 H	na	na	na	na	na	1.0	2.4	2.5	2.3
Barclays	4.9	na	na	na	na	na	na	4.1	4.0	4.3	4.6	na	na	na	na	na	1.5	2.2	2.1	2.0
Chan Economics	4.9	7.9	4.8	4.8	4.9	5.0	4.8	4.3	3.8	3.9	4.1	5.1	6.1	4.5	6.7	113.8	1.5	2.1	2.3	2.0
ING	4.9	na	na	na	na	na	na	3.7	3.5 L	3.5 L	3.8 L	na	na	na	na	na	0.1	na	na	na
Wells Fargo	4.8	8.0	4.9	4.8	4.6	4.5	4.3	3.9	3.8	3.9	4.1	5.1	6.1	4.5	6.6	na	1.1	2.0	2.3	2.0
Goldman Sachs & Co.	4.6	na	na	na	5.3	na	na	4.0	3.7	3.8	4.0	na	na	na	na	na	2.5 H	1.9	2.5	2.0
Georgia State University	4.5	7.6	na	na	4.5	4.2 L	4.2	3.8	3.7	3.9	4.2	4.8	5.9	na	6.8	na	-0.2	2.5	2.7	2.6
TS Lombard	4.5	7.6	4.5 L	4.5	4.4 L	4.5	4.3	4.0	3.9	4.0	4.1	4.9	5.7	4.0	5.8 L	110.0 L	0.4	2.0	2.0	2.0
NatWest Markets	4.3 L	7.5 L	na	4.4 L	4.6	4.7	4.8	3.6 L	3.8	4.3	4.7 H	5.2	6.1	4.9 H	6.7	na	-1.0	1.5	1.7	1.9
February Consensus	**5.1**	**8.2**	**5.2**	**5.1**	**5.1**	**5.0**	**4.7**	**4.2**	**3.9**	**4.0**	**4.2**	**5.0**	**6.0**	**4.3**	**6.6**	**114.9**	**0.9**	**2.2**	**2.4**	**2.3**
Top 10 Avg.	5.3	8.5	5.4	5.3	5.3	5.2	4.9	4.5	4.2	4.3	4.5	5.2	6.2	4.5	6.9	115.8	1.9	2.7	2.9	2.6
Bottom 10 Avg.	4.7	8.0	5.0	4.9	4.7	4.7	4.4	3.8	3.7	3.8	4.0	4.7	5.7	4.0	6.3	114.0	-0.2	1.7	2.0	1.9
January Consensus	5.1	8.2	5.1	5.1	5.1	5.0	4.7	4.2	4.0	4.1	4.3	5.0	6.0	4.3	6.8	114.9	0.5	2.3	2.4	2.2
Number of Forecasts Changed From A Month Ago:																				
Down	10	7	7	4	9	12	14	15	15	13	13	6	8	6	14	6	2	16	9	12
Same	22	18	13	13	19	11	9	15	15	18	14	11	9	9	12	7	11	12	16	11
Up	5	5	5	4	4	5	5	6	6	6	8	5	4	3	2	5	24	7	11	12
Diffusion Index	43%	47%	46%	50%	42%	38%	34%	38%	38%	41%	43%	48%	40%	42%	29%	47%	80%	37%	53%	50%

Third Quarter 2024

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term: 1 Federal Funds Rate	2 Prime Bank Rate	3 SOFR Rate	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term: 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term: 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For ---Qtr.--- A. Fed's Adv Fgn Econ $ Index	(Q-Q % Change) (SAAR): B. Real GDP	C. GDP Price Index	D. Cons. Price Index	E. PCE Price Index
Santander Capital Markets	5.3 H	8.5 H	5.3	5.2 H	5.2 H	5.1 H	4.8	4.6 H	4.3 H	4.3	4.5	5.3	6.3	3.8 L	6.8	114.0	0.9	2.7	2.7	2.3
J.P. Morgan Chase	5.2	na	na	na	na	na	na	3.9	3.6	3.8	4.2	na	na	na	na	na	0.5	2.5	2.8	2.4
PNC Financial Services Corp.	5.2	8.3	5.2	na	5.0	4.9	4.6	4.2	4.0	4.0	4.2	na	6.6 H	4.9 H	6.6	118.5 H	-0.8	1.7 L	1.6 L	1.5
BMO Capital Markets	5.1	8.2	5.0	5.1	5.2 H	5.0	4.5	4.0	3.9	3.8	4.2	4.8	5.9	4.2	6.4	114.1	1.3	2.3	2.5	2.3
Chmura Economics & Analytics	5.1	8.3	5.1	5.1	5.1	5.1 H	5.0 H	4.6 H	4.2	4.2	4.4	5.2	na	na	6.7	na	-0.5	3.1	2.9 H	2.6
Economist Intelligence Unit	5.1	8.1	na	5.0	5.0	4.8	4.6	4.1	3.9	3.9	3.9	na	na	na	6.5	na	0.5	na	2.3	na
MacroFin Analytics & Rutgers Bus School	5.1	8.3	5.1	5.1	5.0	5.1 H	4.5	4.2	3.8	3.8	3.9	4.9	5.7	4.0	6.8	114.9	1.3	2.2	2.3	2.4
Action Economics	5.0	8.2	5.6 H	5.0	5.0	4.8	4.6	4.2	4.2	4.2	4.3	4.8	5.8	4.3	7.3 H	116.6	1.7	2.0	2.4	1.8
Comerica Bank	5.0	8.2	5.0	na	5.0	4.8	4.3	3.7	3.5	3.6	3.8 L	4.5	5.4 L	na	5.9 L	na	1.9	4.0 H	2.3	2.3
The Lonski Group	5.0	8.1	4.9	5.0	5.1	4.9	4.5	4.2	3.8	3.8	4.0	5.0	5.8	4.1	6.3	116.7	0.8	2.0	1.9	2.1
Daiwa Capital Markets America	4.9	8.0	4.9	na	4.4	na	na	3.7	3.5	3.6	4.3	na	na	na	6.0	115.0	-0.6	2.3	2.3	2.2
KPMG	4.9	8.1	4.9	4.6	4.8	4.8	4.4	4.0	3.6	3.6	3.8 L	4.4	5.6	na	6.1	na	1.4	2.2	2.9 H	2.4
Naroff Economics LLC	4.9	7.9	4.8	4.8	4.7	4.7	4.7	4.3	3.8	3.9	4.2	4.8	5.4 L	4.0	6.3	114.0	3.6 H	2.6	2.8	2.6
Oxford Economics	4.9	8.0	4.9	na	4.9	4.7	4.3	3.9	3.6	3.9	4.1	3.9 L	na	na	6.6	114.3	0.8	2.5	2.3	2.1
Roberts Capital Advisors	4.9	8.2	4.9	4.9	5.0	4.8	4.7	4.4	4.2	4.3	4.6	5.4	6.4	4.6	6.5	115.5	2.2	2.4	2.4	2.3
The Northern Trust Company	4.9	8.0	4.8	5.0	4.8	4.7	4.5	4.1	4.2	4.2	4.5	5.3	6.4	4.5	6.7	114.0	0.9	2.2	2.3	2.3
EY-Parthenon	4.8	na	na	na	4.7	na	na	na	na	3.8	na	na	na	na	na	na	1.6	2.2	2.4	2.2
Fannie Mae	4.8	7.9	na	na	4.4	4.3	4.1	3.9	3.9	4.1	4.3	na	na	na	6.3	na	1.2	2.3	2.7	2.4
GLC Financial Economics	4.8	7.9	4.8	4.7	4.7	4.6	4.8	4.4	4.0	4.0	4.3	5.0	6.1	4.3	6.6	115.0	1.0	2.4	2.4	2.2
Regions Financial Corporation	4.8	7.8	4.8	4.9	4.9	4.8	4.5	3.9	3.8	4.0	4.2	5.0	6.1	4.3	6.5	114.3	2.0	2.7	2.3	2.3
S&P Global Market Intelligence	4.8	7.9	4.8	na	4.6	4.4	4.1	3.7	3.4 L	3.5 L	3.8 L	na	na	na	6.1	na	1.5	2.2	2.8	2.4
Scotiabank Group	4.8	na	4.6	na	4.2	na	na	3.5	3.7	3.8	3.8 L	na	na	na	na	na	1.0	3.1	2.9 H	2.7 H
Via Nova Investment Mgt.	4.8	8.0	4.8	4.9	4.8	4.8	4.8	4.0	3.9	3.9	4.1	5.0	5.7	3.9	6.7	112.0 L	2.5	2.1	2.1	2.1
DePrince & Assoc.	4.7	7.9	4.7	4.8	4.8	4.7	4.3	3.9	3.7	3.9	4.2	5.0	5.9	4.2	6.2	116.1	1.5	2.5	2.6	2.4
Loomis, Sayles & Company	4.7	7.8	4.6	4.6	4.8	4.7	4.3	3.6	3.6	3.8	3.9	4.6	5.6	3.8 L	6.4	114.1	-1.3	1.8	1.9	1.4 L
Moody's Analytics	4.7	7.8	4.6	4.6	4.5	4.5	4.5	4.4	4.2	4.1	4.6	5.6 H	6.5	4.3	6.7	na	1.6	1.7 L	2.6	2.2
Bank of America	4.6	na	na	na	na	na	na	4.3	4.3 H	4.3	4.7 H	na	na	na	na	na	1.5	2.7	2.6	2.3
Barclays	4.6	na	na	na	na	na	na	3.9	4.0	4.4 H	4.6	na	na	na	na	na	1.0	2.6	2.7	2.4
Chan Economics	4.6	7.6	4.5	4.5	4.6	4.7	4.5	4.0	3.5	3.6	3.8 L	4.8	5.8	4.2	6.4	113.7	0.5	2.1	2.3	2.0
Nomura Securities, Inc.	4.6	7.8	na	na	na	na	na	3.9	4.0	4.0	na	na	na	na	na	na	1.7	1.9	2.1	2.2
Societe Generale	4.6	7.8	4.6	na	4.4	4.1	3.7	3.3	3.5	3.6	3.9	na	na	na	na	na	-1.5 L	1.8	2.2	2.5
Goldman Sachs & Co.	4.4	na	na	na	5.0	na	na	3.8	3.7	3.9	4.1	na	na	na	na	na	2.3	2.0	2.4	2.0
ING	4.4	na	na	na	na	na	na	3.4	3.4 L	3.5 L	3.9	na	na	na	na	na	-1.0	na	na	na
Wells Fargo	4.4	7.5	4.4	4.4	4.4	4.2	4.0	3.7	3.6	3.7	4.0	4.9	5.9	4.3	6.4	na	0.5	1.7 L	2.0	1.7
Georgia State University	4.0	7.2	na	na	3.9	3.7 L	3.6 L	3.4	3.4 L	3.6	3.9	4.5	5.6	na	6.4	na	0.6	2.6	2.1	2.5
TS Lombard	4.0	7.1	4.0 L	4.0	3.9	4.0	4.1	4.3	4.2	4.3	4.4	5.1	6.0	4.3	6.1	112.0 L	1.5	2.0	2.0	2.0
NatWest Markets	3.3 L	6.5 L	na	3.4 L	3.6 L	3.7 L	3.8	3.2 L	3.5	4.1	4.6	4.9	5.8	4.6	6.4	na	-0.5	1.9	1.7	1.7
February Consensus	**4.7**	**7.9**	**4.8**	**4.7**	**4.7**	**4.6**	**4.4**	**4.0**	**3.8**	**3.9**	**4.2**	**4.9**	**5.9**	**4.2**	**6.5**	**114.7**	**0.9**	**2.3**	**2.4**	**2.2**
Top 10 Avg.	5.1	8.2	5.1	5.0	5.1	4.9	4.7	4.4	4.2	4.2	4.5	5.2	6.2	4.4	6.8	115.7	2.1	2.9	2.8	2.5
Bottom 10 Avg.	4.3	7.5	4.6	4.4	4.2	4.2	4.0	3.5	3.5	3.6	3.9	4.6	5.6	4.1	6.2	113.7	-0.5	1.9	2.0	1.8
January Consensus	4.8	7.9	4.8	4.7	4.7	4.6	4.4	4.0	3.9	3.9	4.2	4.9	6.0	4.2	6.6	114.8	0.7	2.3	2.4	2.2
Number of Forecasts Changed From A Month Ago:																				
Down	10	9	6	4	7	9	13	15	16	12	12	6	7	4	13	6	6	8	8	13
Same	19	14	13	11	19	12	8	14	13	18	15	11	9	10	8	7	14	17	18	11
Up	8	7	6	6	6	7	7	7	7	7	8	5	5	4	7	5	17	10	10	11
Diffusion Index	47%	47%	50%	55%	48%	46%	39%	39%	38%	43%	44%	48%	45%	50%	39%	47%	65%	53%	53%	47%

Fourth Quarter 2024

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	1 Federal Funds Rate	2 Prime Bank Rate	3 SOFR Rate	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Adv Fgn Econ $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index	E. PCE Price Index
	Percent Per Annum -- Average For Quarter															Avg. For ---Qtr.---	(Q-Q % Change) (SAAR)			
	Short-Term							Intermediate-Term			Long-Term									
Santander Capital Markets	5.1 H	8.3 H	5.1	5.0 H	4.7	4.6	4.5	4.4	4.2	4.1	4.4	5.3	6.4	3.6 L	6.5	113.0	1.1	2.5	2.5	2.1
Chmura Economics & Analytics	4.9	8.0	4.9	4.9	4.9 H	4.9 H	4.9 H	4.6 H	4.3	4.3	4.5	5.3	na	na	6.6	na	1.0	2.8	2.8	2.5 H
PNC Financial Services Corp.	4.9	8.1	4.9	na	4.5	4.4	4.3	4.1	4.0	4.1	4.2	na	6.3	4.8 H	6.5	119.8 H	-1.2	1.8	1.8	1.7
Action Economics	4.8	7.9	5.3 H	4.8	4.7	4.6	4.3	4.2	4.1	4.1	4.3	4.8	5.8	4.3	7.3 H	116.8	1.7	1.5	2.4	1.8
Comerica Bank	4.8	8.0	4.8	na	4.6	4.4	3.8	3.3	3.2 L	3.3 L	3.6 L	4.3	5.2 L	na	5.5 L	na	2.0	4.0 H	2.2	2.1
Economist Intelligence Unit	4.8	7.8	na	4.7	4.8	4.6	4.5	4.0	3.8	3.7	3.8	na	na	na	6.4	na	0.9	na	2.0	na
J.P. Morgan Chase	4.8	na	na	na	na	na	na	3.5	3.5	3.7	4.2	na	na	na	na	na	0.8	2.3	2.4	2.0
BMO Capital Markets	4.7	7.8	4.6	4.7	4.7	4.6	4.2	3.9	3.8	3.8	4.1	4.9	5.9	4.3	6.3	113.9	1.5	2.1	2.2	2.0
Oxford Economics	4.7	7.8	4.7	na	4.6	4.4	4.0	3.6	3.5	3.8	4.0	3.8 L	na	na	6.5	113.6	1.1	2.6	2.4	2.2
Roberts Capital Advisors	4.7	7.8	4.7	4.7	4.7	4.5	4.4	4.1	4.2	4.2	4.5	5.3	6.3	4.6	6.3	115.0	2.2	2.3	2.4	2.3
MacroFin Analytics & Rutgers Bus School	4.6	7.8	4.6	4.6	4.4	4.6	4.3	4.1	3.7	3.8	3.8	4.9	5.7	3.9	6.7	114.7	1.6	2.2	2.1	2.2
The Northern Trust Company	4.6	7.7	4.5	4.7	4.4	4.3	4.1	4.0	4.1	4.1	4.4	5.4	6.5 H	4.5	6.6	112.0	1.0	2.2	2.2	2.2
EY-Parthenon	4.5	na	na	na	4.5	na	na	na	na	3.7	na	na	na	na	na	na	1.7	2.1	2.1	2.1
Fannie Mae	4.5	7.6	na	na	4.1	4.1	4.0	3.9	3.9	4.1	4.3	na	na	na	6.2	na	1.5	2.3	2.9 H	2.5 H
KPMG	4.5	7.6	4.5	4.1	4.3	4.3	4.0	3.7	3.4	3.5	3.8	4.3	5.5	na	5.9	na	1.6	2.1	2.1	2.1
Moody's Analytics	4.5	7.7	4.5	4.4	4.3	4.3	4.3	4.2	4.2	4.1	4.6	5.6 H	6.5 H	4.3	6.6	na	1.5	1.9	2.4	2.4
S&P Global Market Intelligence	4.5	7.7	4.6	na	4.3	4.1	3.9	3.5	3.2 L	3.4	3.7	na	na	na	5.8	na	1.7	2.1	2.0	2.0
The Lonski Group	4.5	7.6	4.4	4.5	4.5	4.3	4.2	4.0	3.7	3.7	3.9	4.9	5.7	4.0	6.1	117.3	1.2	2.1	2.0	2.2
Via Nova Investment Mgt.	4.5	7.8	4.6	4.6	4.5	4.5	4.5	3.9	3.9	3.9	4.0	5.0	5.7	3.9	6.7	110.0 L	2.5	2.1	2.0	2.1
Bank of America	4.4	na	na	na	na	na	na	4.0	4.2	4.3	4.8 H	na	na	na	na	na	1.5	2.3	2.0	2.0
Barclays	4.4	na	na	na	na	na	na	3.8	4.0	4.4	4.6	na	na	na	na	na	1.0	2.6	2.7	2.4
Chan Economics	4.4	7.4	4.3	4.3	4.4	4.5	4.3	3.8	3.3	3.4	3.6 L	4.6	5.6	4.0	6.2	113.5	0.8	2.1	2.3	2.0
Daiwa Capital Markets America	4.4	7.5	4.4	na	4.0	na	na	3.4	3.3	3.5	4.2	na	na	na	5.8	115.0	0.5	2.2	2.2	2.1
GLC Financial Economics	4.4	7.6	4.5	4.4	4.3	4.3	4.5	4.2	3.8	3.9	4.2	4.9	6.0	4.3	6.4	114.9	1.3	2.3	2.3	2.2
Nomura Securities, Inc.	4.4	7.5	na	na	na	na	na	3.8	3.8	4.0	na	na	na	na	na	na	1.8	1.6	2.0	2.2
Regions Financial Corporation	4.4	7.4	4.4	4.5	4.5	4.4	4.4	3.6	3.6	3.9	4.1	4.9	6.0	4.2	6.4	114.0	2.4	2.5	2.2	2.1
DePrince & Assoc.	4.3	7.5	4.3	4.4	4.4	4.3	3.9	3.6	3.5	3.8	4.2	5.0	5.9	4.2	6.0	115.9	1.9	2.5	2.6	2.4
Naroff Economics LLC	4.3	7.3	4.3	4.4	4.3	4.5	4.6	4.3	3.7	3.8	3.9	4.8	5.3	4.0	6.1	113.3	2.2	2.5	2.5	2.4
Societe Generale	4.2	7.3	4.2	na	3.9	3.6	3.3	3.1 L	3.5	3.6	3.9	na	na	na	na	na	3.0 H	1.8	2.2	2.3
Goldman Sachs & Co.	4.1	na	na	na	4.8	na	na	3.7	3.7	4.0	4.2	na	na	na	na	na	2.0	1.9	2.3	1.9
Loomis, Sayles & Company	4.1	7.3	4.1	4.0	4.2	4.2	3.9	3.4	3.4	3.6	3.8	4.4	5.4	3.6 L	6.0	114.0	-2.2 L	1.9	1.9	1.6 L
Wells Fargo	4.1	7.3	4.2	4.1	4.1	4.0	3.7	3.5	3.5	3.6	3.9	4.8	5.8	4.2	6.1	na	1.0	2.0	2.2	2.0
Scotiabank Group	4.0	na	3.8 L	na	3.8	na	na	3.4	3.6	3.9	4.0	na	na	na	na	na	1.8	0.5 L	2.5	2.3
ING	3.9	na	na	na	na	na	na	3.3	3.3	3.5	3.9	na	na	na	na	na	1.2	na	na	na
TS Lombard	3.8	6.9	3.8 L	3.8	3.7	3.8	4.0	4.3	4.4 H	4.5 H	4.6	5.4	6.2	4.5	6.3	115.0	2.5	2.5	2.5	2.5 H
Georgia State University	3.6	6.8	na	na	3.5	3.2 L	3.1 L	3.4	3.3	3.5	3.8	4.5	5.6	na	6.4	na	0.7	2.3	1.7 L	2.1
NatWest Markets	3.1 L	6.3 L	na	3.2 L	3.4 L	3.5	3.6	3.1 L	3.4	4.0	4.6	4.8	5.7	4.5	6.3	na	1.5	2.1	2.7	2.3
February Consensus	**4.4**	**7.6**	**4.5**	**4.4**	**4.3**	**4.3**	**4.1**	**3.8**	**3.7**	**3.9**	**4.1**	**4.9**	**5.9**	**4.2**	**6.3**	**114.5**	**1.4**	**2.2**	**2.3**	**2.2**
Top 10 Avg.	4.8	7.9	4.8	4.7	4.7	4.6	4.5	4.3	4.2	4.2	4.5	5.2	6.2	4.4	6.6	115.8	2.3	2.7	2.6	2.4
Bottom 10 Avg.	3.9	7.2	4.2	4.1	3.9	3.9	3.7	3.3	3.3	3.5	3.8	4.5	5.5	4.0	6.0	113.2	0.3	1.7	2.0	1.9
January Consensus	4.4	7.6	4.5	4.4	4.3	4.3	4.2	3.8	3.8	3.9	4.1	4.8	5.9	4.2	6.4	114.7	1.2	2.2	2.3	2.2
Number of Forecasts Changed From A Month Ago:																				
Down	9	7	5	2	10	8	10	12	14	12	12	6	7	5	13	7	10	10	11	12
Same	20	16	14	13	16	13	12	17	17	19	16	9	8	9	9	7	15	18	17	14
Up	8	7	6	6	6	7	6	7	5	6	7	7	6	4	6	4	12	7	8	9
Diffusion Index	49%	50%	52%	60%	44%	48%	43%	43%	38%	42%	43%	52%	48%	47%	38%	42%	53%	46%	46%	46%

First Quarter 2025

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	1 Federal Funds Rate	2 Prime Bank Rate	3 SOFR Rate	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Adv Fgn Econ $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index	E. PCE Price Index
	Percent Per Annum -- Average For Quarter															Avg. For ---Qtr.---	(Q-Q % Change) (SAAR)			
	Short-Term							Intermediate-Term			Long-Term									
Chmura Economics & Analytics	4.6 H	7.8 H	4.6	4.7 H	4.6 H	4.6 H	4.7 H	4.7 H	4.3	4.4	4.6	5.3	na	na	6.4	na	1.8	2.5	2.6	2.4
Economist Intelligence Unit	4.6 H	7.6	na	4.5	4.6 H	4.4	4.3	3.8	3.6	3.6	3.7	na	na	na	6.3	na	1.9	na	2.1	na
Santander Capital Markets	4.6 H	7.8 H	4.6	4.6	4.2	4.1	4.0	4.0	3.8	3.8	4.1	4.9	6.0	3.3 L	6.1	112.0	1.3	2.8	2.4	2.1
Action Economics	4.5	7.7	5.1 H	4.5	4.5	4.3	4.1	4.0	4.1	4.1	4.2	4.7	5.7	4.2	7.2 H	117.0	1.7	1.5	2.4	1.8
Oxford Economics	4.5	7.6	4.5	na	4.3	4.2	3.9	3.5	3.4	3.7	3.8	3.7 L	na	na	6.4	112.7	1.3	2.3	2.0	2.1
PNC Financial Services Corp.	4.4	7.6	4.4	na	4.1	4.1	4.1	4.0	4.0	4.1	4.2	na	6.1	4.7	6.4	120.7 H	-0.2 L	2.0	1.9	1.7
Roberts Capital Advisors	4.4	7.6	4.4	4.5	4.5	4.3	4.2	4.0	4.0	4.0	4.3	5.2	6.2	4.5	6.1	115.0	2.1	2.3	2.4	2.3
BMO Capital Markets	4.3	7.4	4.2	4.3	4.4	4.3	4.0	3.7	3.7	3.7	4.1	4.7	5.7	4.1	6.3	113.6	2.0	1.6	2.3	2.1
Comerica Bank	4.3	7.5	4.3	na	4.2	4.0	3.4	3.0	3.1	3.3	3.6	4.3	5.2 L	na	5.3 L	na	1.7	3.6 H	2.0	2.2
J.P. Morgan Chase	4.3	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.0	2.3	2.5	2.1
Moody's Analytics	4.3	7.5	4.3	4.2	4.1	4.1	4.1	4.1	4.1	4.1	4.6	5.6 H	6.5 H	4.3	6.5	na	1.6	2.2	2.3	2.3
Regions Financial Corporation	4.3	7.3	4.2	4.3	4.3	4.3	4.3	3.5	3.6	3.8	4.0	4.8	5.8	4.2	6.4	113.7	2.5	2.4	2.3	2.1
Via Nova Investment Mgt.	4.3	7.5	4.3	4.4	4.2	4.3	4.4	3.9	4.1	4.1	4.1	5.2	5.8	4.1	6.9	110.0 L	2.5	2.0	2.0	2.1
GLC Financial Economics	4.2	7.3	4.3	4.2	4.1	4.1	4.2	4.0	3.7	3.7	4.1	4.8	5.9	4.2	6.3	114.6	1.8	2.2	2.2	2.2
KPMG	4.2	7.3	4.1	3.8	4.0	4.1	3.9	3.6	3.3	3.4	3.7	4.2	5.5	na	5.6	na	1.4	2.1	1.3 L	1.7
S&P Global Market Intelligence	4.2	7.3	4.2	na	3.9	3.7	3.6	3.3	3.1	3.3	3.6	na	na	na	5.6	na	1.5	2.1	1.3 L	1.7
Bank of America	4.1	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.0	2.6	2.5	2.4
Barclays	4.1	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	1.0	2.6	2.8	2.4
Chan Economics	4.1	7.1	4.0	4.0	4.1	4.2	4.0	3.5	3.0	3.1 L	3.3 L	4.3	5.3	3.7	5.9	113.2	1.5	2.0	2.2	1.9
MacroFin Analytics & Rutgers Bus School	4.1	7.3	4.1	4.1	3.9	4.1	4.1	4.0	3.7	3.7	3.8	4.8	5.6	3.9	6.7	114.5	2.0	2.0	2.0	2.0
Nomura Securities, Inc.	4.1	7.3	na	na	na	na	na	3.6	3.8	4.0	na	na	na	na	na	na	2.2	1.6	2.4	2.3
The Northern Trust Company	4.1	7.3	4.1	4.2	3.9	3.7	3.5	3.8	3.9	4.1	4.4	5.4	6.5 H	4.5	6.6	111.0	1.4	2.1	2.1	2.1
Daiwa Capital Markets America	4.0	7.1	4.0	na	3.8	na	na	3.1	3.1	3.3	4.1	na	na	na	5.7	115.0	1.3	2.2	2.0	2.0
DePrince & Assoc.	4.0	7.1	4.0	4.0	4.0	4.0	3.6	3.4	3.4	3.7	4.1	5.0	5.8	4.2	5.9	115.8	2.0	2.5	2.6	2.4
EY-Parthenon	4.0	na	na	na	3.9	na	na	na	na	3.6	na	na	na	na	na	na	2.0	2.0	2.1	2.1
Fannie Mae	4.0	7.2	na	na	4.0	3.9	3.9	3.8	3.9	4.1	4.3	na	na	na	6.0	na	1.6	2.3	2.8	2.4
TS Lombard	4.0	7.1	4.0	4.0	3.9	4.0	4.2	4.4	4.7 H	4.8 H	4.9 H	5.6 H	6.5 H	4.8 H	6.6	120.0	2.0	3.0	3.0 H	3.0 H
Goldman Sachs & Co.	3.9	na	na	na	4.6 H	na	na	3.6	3.7	4.0	4.2	na	na	na	na	na	2.0	2.1	2.3	2.1
The Lonski Group	3.9	7.0	3.9	4.0	3.9	3.8	3.8	3.8	3.6	3.6	3.8	4.8	5.5	3.9	5.8	117.9	1.8	2.2	1.4	1.9
Naroff Economics LLC	3.8	6.8	3.9	3.9	3.9	4.0	4.2	4.2	3.7	3.9	4.1	4.9	5.4	3.9	5.9	113.8	3.0	2.4	2.4	2.3
Scotiabank Group	3.8	na	3.6 L	na	3.3 L	na	na	3.4	3.5	4.0	4.0	na	na	na	na	na	1.5	1.1 L	2.4	2.2
Wells Fargo	3.8	7.0	3.9	3.8	3.9	3.7	3.6	3.4	3.4	3.6	3.9	4.8	5.8	4.2	5.9	na	1.8	2.3	2.5	2.3
Loomis, Sayles & Company	3.7	6.9	3.7	3.6	3.8	3.7	3.5	3.3	3.3	3.5	3.8	4.3	5.3	3.5	5.8	113.9	1.0	2.0	2.5	2.0
Georgia State University	3.6	6.7	na	na	3.4	3.1 L	3.1	3.3	3.1	3.4	3.7	4.4	5.5	na	6.0	na	1.4	2.0	1.4	1.4
Societe Generale	3.6	6.8	3.6 L	na	3.4	3.2	3.0 L	2.9 L	2.7 L	3.2	3.5	na	na	na	na	na	3.7 H	2.0	2.2	2.2
ING	3.4	na	na	na	na	na	na	3.2	3.6	3.8	4.2	na	na	na	na	na	1.5	na	na	na
NatWest Markets	3.1 L	6.3 L	na	3.2 L	3.4	3.5	3.6	3.1	3.4	4.0	4.6	4.8	5.7	4.5	6.3	na	2.1	1.8	1.4	1.3 L
February Consensus	**4.1**	**7.3**	**4.2**	**4.1**	**4.0**	**4.0**	**3.9**	**3.7**	**3.6**	**3.8**	**4.0**	**4.8**	**5.8**	**4.1**	**6.2**	**114.7**	**1.8**	**2.2**	**2.2**	**2.1**
Top 10 Avg.	4.5	7.6	4.5	4.4	4.4	4.3	4.3	4.1	4.1	4.2	4.4	5.2	6.1	4.4	6.6	116.4	2.4	2.7	2.6	2.4
Bottom 10 Avg.	3.7	6.9	3.9	3.8	3.7	3.6	3.5	3.2	3.2	3.4	3.7	4.4	5.5	3.9	5.7	112.8	1.1	1.8	1.7	1.7
January Consensus	4.1	7.2	4.2	4.1	4.0	4.0	3.9	3.7	3.6	3.8	4.0	4.8	5.8	4.1	6.3	114.4	1.8	2.2	2.2	2.1
Number of Forecasts Changed From A Month Ago:																				
Down	10	7	6	3	8	8	11	9	10	11	11	6	8	4	11	7	10	10	6	7
Same	19	16	12	13	18	14	11	14	15	14	11	8	6	9	11	7	17	20	22	22
Up	8	7	7	5	6	6	6	9	7	8	9	7	6	4	5	4	10	5	8	6
Diffusion Index	47%	50%	52%	55%	47%	46%	41%	50%	45%	45%	47%	52%	45%	50%	39%	42%	50%	43%	53%	49%

Second Quarter 2025

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	1 Federal Funds Rate	2 Prime Bank Rate	3 SOFR Rate	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Adv Fgn Econ $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index	E. PCE Price Index
	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term			Long-Term					Avg. For ---Qtr.---	(Q-Q % Change) (SAAR)			
TS Lombard	4.5 H	7.6 H	4.5	4.5 H	4.4	4.5 H	4.6 H	4.8 H	5.2 H	5.3 H	5.4 H	6.1 H	7.0 H	5.3 H	7.1	120.0	2.0	3.5 H	3.5 H	3.5 H
Chmura Economics & Analytics	4.4	7.5	4.4	4.4	4.3	4.4	4.5	4.6	4.4	4.4	4.5	5.2	na	na	6.2	na	2.7	2.4	2.5	2.4
Economist Intelligence Unit	4.4	7.4	na	4.3	4.3	4.2	4.1	3.7	3.5	3.5	3.6	na	na	na	6.0	na	2.2	na	2.2	na
Roberts Capital Advisors	4.4	7.6 H	4.4	4.5 H	4.5 H	4.3	4.2	4.0	4.0	4.0	4.3	5.2	6.2	4.5	6.1	115.0	2.2	2.2	2.3	2.2
Action Economics	4.3	7.4	4.8 H	4.3	4.2	4.1	3.8	3.9	4.0	4.0	4.2	4.7	5.7	4.1	7.2 H	117.2	1.7	1.9	2.4	1.8
BMO Capital Markets	4.1	7.2	4.0	4.1	4.1	4.0	3.8	3.6	3.7	3.7	4.1	4.7	5.7	4.2	6.3	113.4	1.9	2.0	2.3	2.1
Moody's Analytics	4.1	7.2	4.0	4.0	3.8	3.9	4.0	4.0	4.0	4.1	4.6	5.5	6.5	4.2	6.4	na	1.6	2.3	2.3	2.3
Oxford Economics	4.1	7.3	4.1	na	4.1	4.0	3.7	3.3	3.2	3.7	3.7	3.7 L	na	na	6.1	111.6	1.7	1.9	2.0	2.0
PNC Financial Services Corp.	4.1	7.3	4.1	na	4.0	4.0	4.0	4.0	4.0	4.1	4.2	na	5.9	4.6	6.3	121.2 H	1.4	1.9	1.9	1.7
Santander Capital Markets	4.1	7.3	4.1	4.1	3.7	3.6	3.5	3.7	3.5	3.5	3.8	4.6	5.7	3.1 L	5.7	111.0	1.5	2.5	2.4	2.1
Regions Financial Corporation	4.0	7.0	4.0	4.1	4.0	4.1	4.2	3.4	3.5	3.7	4.0	4.7	5.7	4.1	6.3	113.9	2.6	2.2	2.3	2.2
Via Nova Investment Mgt.	4.0	7.3	4.0	4.1	3.9	4.0	4.1	3.8	4.0	4.0	4.1	5.1	5.7	4.0	6.8	110.0 L	2.5	2.0	2.0	2.0
Bank of America	3.9	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.0	2.3	2.1	2.0
Barclays	3.9	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	1.5	2.3	2.3	2.1
Chan Economics	3.9	6.9	3.8	3.8	3.9	4.0	3.8	3.3	2.8	2.9 L	3.1 L	4.1	5.1 L	3.5	5.7	113.0	1.0 L	2.0	2.2	1.9
Comerica Bank	3.9	7.1	3.9	na	3.8	3.5	3.1	2.7 L	2.9	3.3	3.6	4.3	5.2	na	5.2 L	na	1.6	3.5 H	2.0	2.2
GLC Financial Economics	3.9	7.1	3.9	3.9	3.8	3.9	3.9	3.8	3.7	3.7	4.1	4.8	5.9	4.2	6.1	114.6	2.1	2.2	2.2	2.2
Nomura Securities, Inc.	3.9	7.0	na	na	na	na	na	3.4	3.7	4.0	na	na	na	na	na	na	2.4	1.2	2.1	1.9
Daiwa Capital Markets America	3.8	6.9	3.7	na	3.6	na	na	3.0	3.1	3.3	4.1	na	na	na	5.7	115.0	1.4	2.1	2.1	2.0
J.P. Morgan Chase	3.8	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.3	2.3	1.9	1.8
DePrince & Assoc.	3.7	6.8	3.7	3.7	3.7	3.7	3.3	3.2	3.3	3.7	4.1	5.0	5.8	4.2	5.8	115.7	2.2	2.4	2.5	2.3
Fannie Mae	3.7	6.8	na	na	3.9	3.8	3.8	3.8	3.9	4.1	4.3	na	na	na	6.0	na	1.6	2.2	2.3	2.2
KPMG	3.7	6.8	3.7	3.3	3.5	3.6	3.4	3.3	3.1	3.3	3.6	4.1	5.4	na	5.4	na	1.6	2.2	1.7	1.8
Goldman Sachs & Co.	3.6	na	na	na	4.3	na	na	3.6	3.7	4.0	4.2	na	na	na	na	na	2.1	2.2	2.4	2.1
MacroFin Analytics & Rutgers Bus School	3.6	6.8	3.6	3.6	3.4	3.7	3.8	3.8	3.7	3.7	3.8	4.8	5.6	3.9	6.7	114.3	2.0	2.0	2.0	2.0
S&P Global Market Intelligence	3.6	6.8	3.6	na	3.4	3.4	3.3	3.1	3.0	3.3	3.6	na	na	na	5.4	na	1.4	2.2	1.7	1.9
The Northern Trust Company	3.6	6.8	3.6	3.7	3.4	3.3	3.4	3.6	3.8	4.0	4.3	5.3	6.4	4.4	6.5	110.0 L	1.6	2.0	2.0	2.0
Wells Fargo	3.6	6.8	3.7	3.6	3.6	3.5	3.4	3.3	3.4	3.5	3.8	4.7	5.7	4.1	5.8	na	2.2	2.1	2.3	2.1
EY-Parthenon	3.5	na	na	na	3.5	na	na	na	na	3.5	na	na	na	na	na	na	2.1	2.0	2.1	2.2
Georgia State University	3.5	6.7	na	na	3.3	3.2	3.2	3.2	3.2	3.4	3.8	4.6	5.6	na	5.8	na	2.2	2.1	1.6	1.7
Loomis, Sayles & Company	3.5	6.7	3.5	3.4	3.6	3.5	3.4	3.3	3.3	3.5	3.8	4.3	5.2	3.5	5.7	113.8	2.2	1.9	2.3	1.8
Scotiabank Group	3.5	na	3.3	na	3.1	na	na	3.3	3.5	4.0	4.0	na	na	na	na	na	1.8	0.9 L	2.4	2.2
The Lonski Group	3.5	6.6	3.4	3.5	3.6	3.6	3.6	3.5	3.5	3.5	3.7	4.8	5.4	3.7	5.5	118.4	2.0	2.0	2.5	2.3
Naroff Economics LLC	3.1	6.1 L	3.2	3.2 L	3.2	3.3	3.5	3.6	3.9	4.1	4.3	5.1	5.6	4.1	5.6	114.4	3.2	2.4	2.2	2.1
NatWest Markets	3.1	6.3	na	3.2 L	3.4	3.5	3.6	3.1	3.4	4.0	4.6	4.8	5.7	4.5	6.3	na	2.0	1.8	1.4 L	1.3 L
Societe Generale	3.1	6.3	3.1 L	na	2.9 L	2.9 L	2.9 L	2.9	2.7 L	3.2	3.5	na	na	na	na	na	4.5 H	2.0	2.2	2.2
ING	2.9 L	na	na	na	na	na	na	3.0	3.7	4.0	4.4	na	na	na	na	na	1.8	na	na	na
February Consensus	**3.8**	**7.0**	**3.9**	**3.9**	**3.8**	**3.8**	**3.7**	**3.5**	**3.6**	**3.8**	**4.0**	**4.8**	**5.8**	**4.1**	**6.1**	**114.6**	**2.0**	**2.1**	**2.2**	**2.1**
Top 10 Avg.	4.3	7.4	4.2	4.2	4.2	4.2	4.1	4.1	4.1	4.2	4.5	5.2	6.1	4.4	6.6	116.6	2.7	2.6	2.5	2.4
Bottom 10 Avg.	3.3	6.6	3.5	3.5	3.3	3.4	3.3	3.1	3.1	3.3	3.6	4.4	5.5	3.8	5.6	112.5	1.5	1.8	1.8	1.8
January Consensus	3.8	7.0	3.8	3.8	3.7	3.8	3.7	3.6	3.6	3.7	4.0	4.7	5.8	4.1	6.1	114.4	2.1	2.1	2.2	2.0
Number of Forecasts Changed From A Month Ago:																				
Down	8	6	5	3	7	8	10	8	9	6	8	4	7	4	8	7	9	5	8	5
Same	23	19	16	14	20	15	14	19	18	22	16	13	10	11	15	8	23	25	24	24
Up	6	5	5	4	5	5	4	5	5	5	7	4	3	2	4	3	5	5	4	6
Diffusion Index	47%	48%	50%	52%	47%	45%	39%	45%	44%	48%	48%	50%	40%	44%	43%	39%	45%	50%	44%	51%

International Interest Rate And Foreign Exchange Rate Forecasts

United States

	Fed Fund Target Rate			10 Yr. Gov't Bond Yield %			Fed's AFE $ Index		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	5.13	4.88	--	4.28	4.33	--	--	--	--
BMO Capital Markets	5.38	5.13	4.38	3.93	3.82	3.74	114.3	114.1	113.6
ING Financial Markets	5.38	4.88	3.88	4.00	3.50	3.50	115.0	112.7	108.0
Moody's Analytics	5.38	5.18	4.57	4.24	4.18	4.11	--	--	--
Northern Trust	5.38	5.32	4.58	4.30	4.20	4.10	116.0	115.0	112.0
Oxford Economics	5.38	5.21	4.71	4.07	3.95	3.81	114.1	114.6	113.6
S&P Global Market Intelligence	--	--	--	3.75	3.58	3.37	--	--	--
Scotiabank	5.13	4.63	3.63	3.70	3.80	4.00	--	--	--
TS Lombard	5.25	4.50	4.00	4.00	4.00	4.75	110.0	110.0	120.0
Wells Fargo	5.38	4.83	4.13	3.95	3.85	3.60	--	--	--
February Consensus	**5.31**	**4.95**	**4.24**	**4.02**	**3.92**	**3.89**	**113.9**	**113.3**	**113.4**
High	5.38	5.32	4.71	4.30	4.33	4.75	116.0	115.0	120.0
Low	5.13	4.50	3.63	3.70	3.50	3.37	110.0	110.0	108.0
Last Months Avg.	5.30	5.02	4.27	4.26	4.09	3.83	115.4	114.3	112.9

Japan

	Policy-Rate Balance Rate			10 Yr. Gov't Bond Yield %			Yen per US$		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	0.00	0.25	--	0.93	0.98	--	152.3	150.0	--
BMO Capital Markets	-0.10	0.00	0.00	0.80	0.89	0.97	143.0	142.0	139.0
ING Financial Markets	-0.10	0.00	0.00	0.60	0.80	1.00	140.0	135.0	130.0
Moody's Analytics	-0.10	-0.03	0.00	0.84	0.84	0.84	142.0	136.6	128.2
Nomura Securities	--	--	--	--	--	--	142.0	140.0	135.0
Northern Trust	-0.10	0.00	0.20	0.75	0.85	0.95	148.0	144.0	138.0
Oxford Economics	-0.04	0.00	0.00	0.66	0.70	0.71	146.2	144.0	137.2
S&P Global Market Intelligence	--	--	--	--	--	--	140.1	135.4	130.0
Scotiabank	--	--	--	--	--	--	150.0	140.0	135.0
TS Lombard	-0.01	0.00	0.10	0.72	0.72	1.47	150.0	140.0	150.0
Wells Fargo	-0.10	0.00	0.00	0.70	0.75	0.70	--	--	--
February Consensus	**-0.07**	**0.03**	**0.04**	**0.75**	**0.82**	**0.95**	**145.4**	**140.7**	**135.8**
High	0.00	0.25	0.20	0.93	0.98	1.47	152.3	150.0	150.0
Low	-0.10	-0.03	0.00	0.60	0.70	0.70	140.0	135.0	128.2
Last Months Avg.	-0.07	-0.01	0.00	0.83	0.84	0.85	145.2	142.6	137.2

United Kingdom

	Official Bank Rate			10 Yr. Gilt Yields %			US$ per Pound Sterling		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	5.00	4.50	--	4.10	4.03	--	1.22	1.26	--
BMO Capital Markets	5.00	4.75	4.25	3.77	3.76	3.74	1.27	1.28	1.28
ING Financial Markets	5.25	5.25	4.25	3.80	3.65	3.65	1.23	1.24	1.28
Moody's Analytics	5.25	5.25	4.57	3.93	3.81	3.65	1.26	1.26	1.26
Nomura Securities	--	--	--	--	--	--	1.27	1.28	1.30
Northern Trust	5.25	5.00	4.25	4.00	3.90	3.80	1.26	1.26	1.29
Oxford Economics	5.25	5.08	4.35	3.77	3.69	3.60	1.28	1.26	1.27
S&P Global Market Intelligence	--	--	--	--	--	--	1.27	1.28	1.29
Scotiabank	5.00	4.50	3.75	--	--	--	1.25	1.30	1.32
TS Lombard	5.25	5.00	4.75	3.90	3.85	4.60	1.27	1.25	1.15
Wells Fargo	5.25	5.00	4.00	3.85	3.80	3.60	--	--	--
February Consensus	**5.17**	**4.93**	**4.27**	**3.89**	**3.81**	**3.81**	**1.26**	**1.27**	**1.27**
High	5.25	5.25	4.75	4.10	4.03	4.60	1.28	1.30	1.32
Low	5.00	4.50	3.75	3.77	3.65	3.60	1.22	1.24	1.15
Last Months Avg.	5.25	5.09	4.20	4.06	3.94	3.65	1.25	1.25	1.26

Switzerland

	SNB Policy Rate			10 Yr. Gov't Bond Yield %			CHF per US$		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	1.75	1.75	--	--	--	--	0.92	0.91	--
BMO Capital Markets	1.75	1.75	1.75	--	--	--	0.86	0.86	0.85
ING Financial Markets	1.75	1.75	1.75	0.90	0.85	1.10	0.88	0.86	0.83
Moody's Analytics	1.75	1.75	1.50	1.55	1.73	1.78	0.86	0.85	0.83
Nomura Securities	--	--	--	--	--	--	0.88	0.87	0.86
Northern Trust	1.50	1.25	1.25	0.95	1.00	1.00	0.87	0.87	0.85
Oxford Economics	1.75	1.75	1.38	0.86	1.03	1.32	0.85	0.87	0.89
S&P Global Market Intelligence	--	--	--	--	--	--	0.86	0.86	0.86
Scotiabank	--	--	--	--	--	--	0.86	0.88	0.88
TS Lombard	1.65	1.50	1.25	0.90	0.90	1.65	0.90	0.90	0.90
Wells Fargo	1.75	1.50	1.00	--	--	--	--	--	--
February Consensus	**1.71**	**1.63**	**1.41**	**1.03**	**1.10**	**1.37**	**0.87**	**0.87**	**0.86**
High	1.75	1.75	1.75	1.55	1.73	1.78	0.92	0.91	0.90
Low	1.50	1.25	1.00	0.86	0.85	1.00	0.85	0.85	0.83
Last Months Avg.	1.75	1.66	1.41	0.95	1.03	1.09	0.89	0.88	0.86

Canada

	O/N MMkt Financing Rate			10 Yr. Gov't Bond Yield %			C$ per US$		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	5.00	4.75	--	--	--	--	1.38	1.37	--
BMO Capital Markets	5.00	4.50	4.00	3.19	3.08	3.00	1.33	1.33	1.31
ING Financial Markets	5.00	4.50	3.50	3.20	3.00	3.25	1.35	1.33	1.28
Moody's Analytics	4.93	4.45	3.50	4.00	4.04	4.04	1.33	1.30	1.26
Nomura Securities	--	--	--	--	--	--	1.34	1.33	1.31
Northern Trust	5.00	4.75	4.00	3.50	3.40	3.30	1.36	1.34	1.30
Oxford Economics	5.00	4.88	4.38	3.25	3.45	3.49	1.33	1.33	1.32
S&P Global Market Intelligence	--	--	--	--	--	--	1.33	1.31	1.30
Scotiabank	4.75	4.25	3.50	3.20	3.35	3.60	1.33	1.28	1.27
TS Lombard	5.00	4.25	3.75	3.50	3.25	2.75	1.35	1.35	1.35
Wells Fargo	5.00	4.75	4.00	3.40	3.30	3.20	--	--	--
February Consensus	**4.96**	**4.56**	**3.83**	**3.41**	**3.36**	**3.33**	**1.34**	**1.33**	**1.30**
High	5.00	4.88	4.38	4.00	4.04	4.04	1.38	1.37	1.35
Low	4.75	4.25	3.50	3.19	3.00	2.75	1.33	1.28	1.26
Last Months Avg.	5.00	4.66	3.77	3.47	3.27	3.14	1.36	1.34	1.31

International Interest Rate And Foreign Exchange Rate Forecasts

Australia

	Official Cash Rate			10 Yr. Gov't Bond Yield %			US$ per A$		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	4.35	4.35	--	--	--	--	0.64	0.65	--
BMO Capital Markets	4.35	4.10	3.60	--	--	--	0.67	0.67	0.67
ING Financial Markets	4.35	4.10	3.60	4.80	4.30	3.70	0.67	0.69	0.70
Moody's Analytics	4.35	4.35	3.85	4.72	4.47	4.14	0.67	0.69	0.72
Nomura Securities	--	--	--	--	--	--	0.68	0.69	0.71
Northern Trust	4.35	4.35	3.60	4.30	4.20	4.10	0.65	0.66	0.69
Oxford Economics	4.46	4.60	4.48	4.55	4.21	4.14	0.66	0.68	0.68
S&P Global Market Intelligence	--	--	--	--	--	--	0.68	0.68	0.69
Scotiabank	--	--	--	--	--	--	0.66	0.68	0.70
TS Lombard	4.32	3.50	3.00	4.20	4.20	4.95	0.65	0.65	0.65
Wells Fargo	4.35	4.35	3.85	--	--	--	--	--	--
February Consensus	**4.36**	**4.21**	**3.71**	**4.51**	**4.28**	**4.21**	**0.66**	**0.67**	**0.69**
High	4.46	4.60	4.48	4.80	4.47	4.95	0.68	0.69	0.72
Low	4.32	3.50	3.00	4.20	4.20	3.70	0.64	0.65	0.65
Last Months Avg.	4.32	4.24	3.75	4.51	4.17	3.86	0.65	0.67	0.69

Euro area

	Main Refinancing Rate			US$ per Euro		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	4.25	3.75	--	1.06	1.07	--
BMO Capital Markets	4.50	4.25	3.75	1.10	1.11	1.12
ING Financial Markets	4.50	4.25	3.75	1.08	1.10	1.15
Moody's Analytics	4.50	4.45	3.53	1.10	1.11	1.12
Nomura Securities	--	--	--	1.12	1.13	1.15
Northern Trust	4.50	4.25	3.25	1.07	1.06	1.12
Oxford Economics	4.50	4.21	3.24	1.09	1.08	1.09
S&P Global Market Intelligence	--	--	--	1.10	1.11	1.13
Scotiabank	4.25	3.75	3.25	1.10	1.12	1.15
TS Lombard	4.00	4.00	3.50	1.10	1.15	1.05
Wells Fargo	4.00	3.50	2.75	--	--	--
February Consensus	**4.33**	**4.05**	**3.38**	**1.09**	**1.10**	**1.12**
High	4.50	4.45	3.75	1.12	1.15	1.15
Low	4.00	3.50	2.75	1.06	1.06	1.05
Last Months Avg.	4.34	3.93	3.32	1.08	1.09	1.12

10 Yr. Gov't Bond Yields %

	Germany			France			Italy			Spain		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	2.67	2.52	--	--	--	--	--	--	--	--	--	--
BMO Capital Markets	2.20	2.26	2.28	--	--	--	--	--	--	--	--	--
ING Financial Markets	2.20	2.10	2.30	2.80	2.70	2.85	4.00	4.00	3.95	3.30	3.20	3.30
Moody's Analytics	2.33	2.33	2.30	2.78	2.74	2.68	4.37	4.36	4.30	3.31	3.33	3.32
Northern Trust	2.35	2.25	2.15	2.85	2.75	2.65	3.90	3.80	3.70	3.25	3.15	3.05
Oxford Economics	2.16	2.17	2.12	2.71	2.70	2.57	3.85	3.89	3.97	3.15	3.16	3.15
TS Lombard	2.60	2.50	2.40	2.95	2.85	2.75	3.90	3.80	3.70	3.35	3.25	3.15
Wells Fargo	2.25	2.20	2.15	--	--	--	--	--	--	--	--	--
February Consensus	**2.35**	**2.29**	**2.24**	**2.82**	**2.75**	**2.70**	**4.00**	**3.97**	**3.92**	**3.27**	**3.22**	**3.19**
High	2.67	2.52	2.40	2.95	2.85	2.85	4.37	4.36	4.30	3.35	3.33	3.32
Low	2.16	2.10	2.12	2.71	2.70	2.57	3.85	3.80	3.70	3.15	3.15	3.05
Last Months Avg.	2.38	2.24	2.11	2.96	2.78	2.72	4.16	4.05	4.01	3.44	3.25	3.23

	Consensus Forecasts 10-year Bond Yields vs U.S. Yield			
	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-3.43	-3.27	-3.10	-2.94
United Kingdom	-0.09	-0.13	-0.11	-0.08
Switzerland	-3.28	-2.99	-2.82	-2.52
Canada	-0.63	-0.62	-0.56	-0.56
Australia	0.04	0.49	0.36	0.32
Germany	-1.85	-1.68	-1.63	-1.64
France	-1.37	-1.20	-1.17	-1.19
Italy	-0.32	-0.02	0.05	0.04
Spain	-0.90	-0.75	-0.70	-0.69

	Consensus Forecasts Policy Rates vs U.S. Target Rate			
	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-5.48	-5.38	-4.98	-4.19
United Kingdom	-0.13	-0.14	-0.03	0.04
Switzerland	-3.63	-3.60	-3.33	-2.82
Canada	-0.38	-0.35	-0.39	-0.41
Australia	-1.03	-0.95	-0.74	-0.52
Euro area	-0.88	-0.98	-0.91	-0.86

Viewpoints:

A Sampling of Views on the Economy, Financial Markets and Government Policy Excerpted from Recent Reports Issued by our Blue Chip Panel Members and Others

Let's Get Real about GDP

US' real private-sector spending lagged real GDP ....

Real GDP outran real private sector spending on final products by 7/10th of a percentage point in 2023. The annual growth rate for real private-sector spending on final goods and services slowed from yearlong 2022's 2.3% to yearlong 2023's 1.8%. By contrast, real GDP growth quickened from 2022's 1.9% to 2023's 2.5%. (Real GDP adds government spending, the trade deficit and the change inventories to real private sector spending on final products.)

Remember real GDP's great head fake of 2022's first half. That was when real GDP's back-to-back annualized quarterly setbacks of -2.0% for Q1-2022 and -0.6% for Q2-2022 were incorrectly viewed by some as evidence of a recession. One of the principal reasons why the unemployment rate did not rise in a manner that would confirm a recession was because real private sector spending on final products posted back-to-back annualized quarterly increases of 1.5% for both the first and second quarters of 2022.

In terms of annualized quarterly growth rates, real private sector purchases of final products slowed from Q3-2023's 3.0% to Q4-2023's 2.6%, which differed considerably from real GDP's accompanying deceleration from 4.9% to 3.3%.

Also, in terms of year-to-year increases, real private sector spending on final products quickened from Q4-2022's 0.8% to Q4-2023's 2.7%, which was more muted than the comparably measured jump by yearly real GDP growth from 0.7% to 3.1%.

Real private sector spending shows highest correlation with US equity market performance ...

In terms of year-on-year growth rates, the market value of US common stock shows a slightly higher correlation of 0.49 with real US private sector purchases of final products compared to the common equity market's 0.45 correlation with real GDP.

Real private sector spending on final products approximates real GDP less real net exports less the change in real inventories less real government spending.

The nominal version of US private sector purchases of final products generates a correlation of 0.42 with the market value of US common stock, where the latter generates a lower correlation of 0.35 with nominal GDP.

Unexpected surge by government spending amplified real GDP's upside surprise …

Though real GDP's annualized quarter-to-quarter growth rate slowed from Q3-2023's 4.9% to Q4-2023's 3.3%, the latter was well above the consensus projection of 2.0% growth. Calendar year 2023's 2.5% annual advance by real GDP far outpaced the consensus' year earlier prediction that called for a 0.5% rise by 2023's US economy.

At the start of 2023, the consensus was looking for a further deceleration of US real GDP following a plunge by real GDP's annual growth rate from 2021's post-COVID surge of 5.8% to 2022's 1.9%. Few expected the US economy would accelerate given monetary tightening that both ratcheted up the federal funds rate from 0.13% to its current 5.38% and the Fed's reduced holdings of US Treasury bonds and mortgage-backed securities.

The upside growth surprise of 2023 owes something not only to the unexpected continuation of massive government stimulus, but also to the overhang of highly liquid assets stemming from 2020-2021's most rapid expansion of the money supply since World War II.

Of special importance to 2023's US economy was the rapid growth of government spending. Yearlong 2023's 4.0% annual advance by real government spending towered over the 2.5% rate of real GDP growth. Real government spending's 4.0% increase for 2023 consisted of gains of 4.2% for real federal spending and 3.8% for real spending by state and local governments.

Without the surge in real government spending, calendar year 2023's 2.5% increase by real GDP slows to an estimated 1.9% matching its 1.9% gain for 2022.

GDP's estimate of government spending excludes social security, Medicare, and Medicaid ...

Worth noting is how real government spending does not include government transfer payments such as social security, Medicare, and Medicaid. Transfer payments enter into GDP via personal spending. For example, while the sum of spending by federal, state, and local governments included in the GDP accounts approximated 17.4% of 2023's GDP, total gross federal outlays for calendar-year 2023 approached 23.0% of GDP.

Calendar-year (CY) 2023's 7.8% annual increase by the sum of outlays for social security, Medicare, and Medicaid was faster than CY 2023's 5.6% annual increase by nominal private sector spending on final goods and services. CY 2023's nominal government spending contained in the GDP accounts that excludes transfer payments grew by a much faster 6.6% annually compared to private sector spending on final products.

Among major categories of GDP's estimate of consumer spending, government support stands out in health care spending. CY 2023's 7.7% annual increase by nominal consumer spending on health care easily outran the 5.7% increase by the rest of consumer spending.

Moreover, government subsidies and tax breaks for green energy projects and electric vehicles explained why CY 2023's 19.4% annual increase by nominal business investment spending on structures was so much faster than the comparably measured gains of 4.2% for business purchases of equipment and 6.2% for business investment in intellectual property products (including software).

Unlike the switch in real government spending's annual percent change from 2022's -0.9% drop to 2023's 4.0% advance, the calendar year growth rates for each of real GDP's broad private-sector categories slowed from 2022 to 2023.

By private sector category, the growth of real consumer spending eased from CY 2022's 2.5% to CY 2023's 2.2%, real business investment spending in capital products slowed from 5.2% to 4.4%, and the annual contraction by real residential investment spending deepened from -9.0% to -10.7%.

Spending on recreational goods led real consumer spending growth in 2023 ...

I doubt if anyone can guess the fastest growing category for CY 2023's real consumer spending? The winner was the 7.6% annual advance by real spending on recreational goods and vehicles. This category has been hot for some time. After surging by 10.3% annually, on average, during the four years ended 2019, real outlays on recreational goods and vehicles accelerated to the 14.3% average annual advance of the four years ended 2023.

But some may view 2023's 7.6% annual advance by real spending on recreational goods and vehicles to be very misleading. Investors may view the 7.6% real increase to be useless information given how nominal, or actual, consumer spending on recreational goods and vehicles rose by a much slower 4.2% annually in 2023. Inflation adjusted, or real, data must be viewed with caution.

Dollar value of consumer spending slows appreciably year-to-year ...

From the perspective of the real world, nominal consumer spending has slowed noticeably from its unsustainably rapid pace of a year ago. The annual increase of nominal consumer spending slowed from CY 2022's 9.2% to CY 2023's 6.0%. In addition, the year-on-year growth rate for nominal consumer spending dropped from Q4-2022's 7.2% to Q4-2023's 5.4%. I think the deceleration by consumer spending is far from over given (i) rising consumer loan delinquency rates, (ii) a historically low personal savings rate, and (iii) the likelihood of slower growth rates for payrolls and employment-derived income.

The annualized quarterly growth rate for real consumer spending eased from Q3-2023's 3.1% to Q4-2023's 2.8%. The latter was slightly above the latest consensus projection of 2.5%. However, not that long ago, the consensus believed Q4-2023's annualized sequential growth rate for real consumer spending would be less than 2%.

Inventory build and thinner trade gap pushes Q4-2023's real GDP growth above 3%

The contribution to GDP from changes in unsold inventories supplied an unexpected lift to Q4-2023's real GDP. Early January's Blue Chip consensus expected the increase in real inventories would drop to $33.2 billion in 2023's final quarter following a jump from Q2-2023's $14.9 billion to Q3-2023's $77.8 billion.

Much to the contrary, Q4-2023 showed an advance by real inventory accumulation to $82.7 billion. So instead of conforming to the consensus forecast and reducing real GDP by -$44.6 billion, the change in inventories added $4.9 billion to Q4-2023's real GDP.

Moreover, the consensus was looking for a widening of Q4-2023's real trade deficit that would have subtracted nearly -$10 billion from real GDP. Instead, the real trade deficit narrowed from Q3-2023's -$930.7 billion to Q4-2023's -$908.2 billion and, thereby, added +$22.5 billion to GDP.

After excluding the volatile additions to real GDP stemming from changes in inventories and changes in the real trade deficit, the remainder of Q4-2023's real GDP grew by a slower 2.7% annualized from Q3-2023's pace. The latter was down from Q3-2023's 3.5% comparably measured gain.

In terms of calendar year growth rates, real GDP excluding the change in inventories and the trade deficit rose from 2022's 1.7% to 2023's 2.2%, where the latter was slower than the 2.5% rise for the entirety of 2023's real GDP.

Furthermore, if we exclude only the 0.6 percentage points of growth supplied CY 2023's US real GDP by a narrower trade deficit, the annual rate of real GDP growth slows to 1.9%, which represents a slowdown from the hybrid metric's 2.3% increase of CY 2022.

John Lonski (The Lonski Group)

U.S. Job Openings Up, Quits Down ...and Jobs are "Plentiful"

Between the two surveys released at the same time.... one on confidence (and jobs) and job availability... these days, I'll go with the job survey as being more important. The two big items to focus on: 1) jobs and 2) inflation expectations

Job openings actually rose in December (Side note: Anyone remember how exciting it was when the number of openings cracked 10 mln? And they stayed there for nearly two years!) We're back over the 9 million mark, which is a 3-month high... and the bulk of the gains were in the private sector. So the good news is that there are options out there... if one is still unemployed or is looking for extra work. The bad news is that it means that the consumer could spend more and that's not what the Fed wants right now.

Firms increased their hires (so they're finding the right person), while the number of people who quit (either for those options noted above or for other personal reasons) fell for the fourth month in a row, which is noteworthy as it suggests that there is less pressure to boost wages. So that is good news.

And, yes, the Conference Board's headline index of consumer confidence showed a bigger-than-expected 6.8 pt jump in January to a 7-month high of 114.8 (lots of excitement around the 'present situation' .... was it the potential for rate cuts?), but check out the jobs section of the survey. Inflation expectations for the next 12 months dropped for the third month in a row to a 46-month low.

"Show of hands! Anyone still finding jobs plentiful these days? How about hard to get?" More respondents found jobs plentiful and fewer found those jobs difficult to come by. Let's go back to the opening segment here .... the good news is that Americans are confident about their job situation; but, the bad news is that means the U.S. economy could stay resilient for longer. Not a bad thing in the grand scheme of things, but bad for Fed Chair Powell. Also, note this suggest that the January jobless rate could fall (we will find out on Friday).

Separately.... House prices are still rising but at a more modest pace.... the S&P CoreLogic Case-Shiller Home Price Index (say that quickly 3x) edged up just 0.2% in November (still sizeable gains in Vegas.... maybe the New Edition reunion is bringing more buyers into town... but they were offset by sizeable declines in San Francisco and Seattle), while the FHFA House Price Index continued to rise at a more sedate rate of 0.3% for the second month in a row.

Bottom Line: It will be challenging to push for earlier rate cuts in this environment.

Jennifer Lee (BMO Capital Markets)

Special Questions:

1. a. At what FOMC meeting will the first FFR cut occur?

Mar 2024	16%	May 2024	41%	Jun 2024	25%	Jul 2024	16%
Sep 2024	0%	Nov 2024	3%	Dec 2024	0%	Later	0%

   b. How much will the FFR target decline in 2024? 112 bps

2. a. What is your estimate of the long-term neutral fed funds rate? 2.86%

   b. Since before the pandemic, has it: increased 79% decreased 7% remained the same 14%

3. The Fed has been reducing its security holdings since the middle of 2022, known as quantitative tightening. Will it halt this reduction once it begins to lower the fed funds rate target? Yes 23% No 77%

4. Changes in monetary policy affect the economy with a lag, possibly long. Is there further meaningful restraint from earlier tightening that the US economy has yet to feel? Yes 80% No 20%

5. Is the US economy headed for a "soft landing," that is a return of inflation to around the Fed's 2% target without the economy experiencing a recession? Yes 81% No 19%

6. a. Did accommodative US fiscal policy play a key role in the resilience of the economy in 2023? Yes 93% No 7%

   b. Do you expect less accommodation in 2024? Yes 77% No 23%

   c. If so, will this slow the economy meaningfully? Yes 52% No 48%

7. What is your US unemployment rate forecast for: Jun 2024 4.1% Dec 2024 4.3%

8. What probability do you attach to a recession beginning over the next 12 months in the:

	US	euro area	UK
Consensus	**39%**	**54%**	**56%**
Top 10	53%	66%	69%
Bot 10	27%	42%	44%

9. a. When will the ECB begin cutting its policy rates?

Q1 2024	Q2 2024	Q3 2024	Q2 2024	Later
9%	61%	26%	4%	0%

   b. When will the BoE begin cutting its Bank rate?

Q1 2024	Q2 2024	Q3 2024	Q2 2024	Later
4%	39%	48%	9%	0%

   c. When will the first hike in the Bank of Japan's short-term policy interest rate occur?

Q1 2024	Q2 2024	Q3 2024	Q2 2024	Later
5%	57%	14%	5%	19%

Databank:

2024 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	····	····	····	····	····	····	····	····	····	····	····	····
Auto & Light Truck Sales (b)	····	····	····	····	····	····	····	····	····	····	····	····
Personal Income (a, current $)	····	····	····	····	····	····	····	····	····	····	····	····
Personal Consumption (a, current $)	····	····	····	····	····	····	····	····	····	····	····	····
Consumer Credit (e)	····	····	····	····	····	····	····	····	····	····	····	····
Consumer Sentiment (U. of Mich.)	78.8	····	····	····	····	····	····	····	····	····	····	····
Household Employment (c)	····	····	····	····	····	····	····	····	····	····	····	····
Nonfarm Payroll Employment (c)	····	····	····	····	····	····	····	····	····	····	····	····
Unemployment Rate (%)	····	····	····	····	····	····	····	····	····	····	····	····
Average Hourly Earnings (All, cur. $)	····	····	····	····	····	····	····	····	····	····	····	····
Average Workweek (All, hrs.)	····	····	····	····	····	····	····	····	····	····	····	····
Industrial Production (d)	····	····	····	····	····	····	····	····	····	····	····	····
Capacity Utilization (%)	····	····	····	····	····	····	····	····	····	····	····	····
ISM Manufacturing Index (g)	····	····	····	····	····	····	····	····	····	····	····	····
ISM Nonmanufacturing Index (g)	····	····	····	····	····	····	····	····	····	····	····	····
Housing Starts (b)	····	····	····	····	····	····	····	····	····	····	····	····
Housing Permits (b)	····	····	····	····	····	····	····	····	····	····	····	····
New Home Sales (1-family, c)	····	····	····	····	····	····	····	····	····	····	····	····
Construction Expenditures (a)	····	····	····	····	····	····	····	····	····	····	····	····
Consumer Price Index (nsa, d)	····	····	····	····	····	····	····	····	····	····	····	····
CPI ex. Food and Energy (nsa, d)	····	····	····	····	····	····	····	····	····	····	····	····
PCE Chain Price Index (d)	····	····	····	····	····	····	····	····	····	····	····	····
Core PCE Chain Price Index (d)	····	····	····	····	····	····	····	····	····	····	····	····
Producer Price Index (nsa, d)	····	····	····	····	····	····	····	····	····	····	····	····
Durable Goods Orders (a)	····	····	····	····	····	····	····	····	····	····	····	····
Leading Economic Indicators (a)	····	····	····	····	····	····	····	····	····	····	····	····
Balance of Trade & Services (f)	····	····	····	····	····	····	····	····	····	····	····	····
Federal Funds Rate (%)	····	····	····	····	····	····	····	····	····	····	····	····
3-Mo. Treasury Bill Rate (%)	····	····	····	····	····	····	····	····	····	····	····	····
10-Year Treasury Note Yield (%)	····	····	····	····	····	····	····	····	····	····	····	····

2023 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	3.0	-0.7	-0.9	0.4	0.7	0.2	0.6	0.7	0.8	-0.3	0.3	0.6
Auto & Light Truck Sales (b)	15.11	14.88	14.93	15.68	15.52	16.06	15.94	15.30	15.77	15.49	15.39	15.89
Personal Income (a, current $)	1.0	0.5	0.5	0.2	0.3	0.2	0.2	0.4	0.3	0.3	0.4	0.3
Personal Consumption (a, current $)	1.6	0.4	-0.1	0.4	0.2	0.4	0.6	0.3	0.8	0.0	0.4	0.7
Consumer Credit (e)	5.4	2.7	4.6	3.5	-0.2	2.9	3.0	-3.5	2.6	1.4	5.7	····
Consumer Sentiment (U. of Mich.)	64.9	66.9	62.0	63.7	59.0	64.2	71.5	69.4	67.9	63.8	61.3	69.7
Household Employment (c)	852	149	523	138	-255	297	205	291	50	-270	586	-683
Nonfarm Payroll Employment (c)	472	248	217	217	281	105	236	165	262	105	173	216
Unemployment Rate (%)	3.4	3.6	3.5	3.4	3.7	3.6	3.5	3.8	3.8	3.8	3.7	3.7
Average Hourly Earnings (All, cur. $)	33.02	33.11	33.20	33.34	33.45	33.60	33.73	33.82	33.91	34.00	34.12	34.27
Average Workweek (All, hrs.)	34.6	34.5	34.4	34.4	34.3	34.4	34.3	34.4	34.4	34.3	34.4	34.3
Industrial Production (d)	1.5	0.9	0.2	0.3	0.1	-0.4	0.1	0.0	-0.2	-0.9	-0.6	1.0
Capacity Utilization (%)	79.6	79.5	79.5	79.8	79.5	78.9	79.5	79.5	79.5	78.7	78.6	78.6
ISM Manufacturing Index (g)	47.4	47.7	46.3	47.1	46.9	46.0	46.4	47.6	49.0	46.7	46.7	47.4
ISM Nonmanufacturing Index (g)	55.2	55.1	51.2	51.9	50.3	53.9	52.7	54.5	53.6	51.8	52.7	50.6
Housing Starts (b)	1.340	1.436	1.380	1.348	1.583	1.418	1.451	1.305	1.356	1.376	1.525	1.460
Housing Permits (b)	1.354	1.482	1.437	1.417	1.496	1.441	1.443	1.541	1.471	1.498	1.467	1.493
New Home Sales (1-family, c)	649	625	640	679	710	683	728	654	698	676	615	664
Construction Expenditures (a)	2.2	0.4	0.6	0.3	2.0	0.5	0.7	2.1	0.4	1.2	0.4	····
Consumer Price Index (nsa, d)	6.4	6.0	5.0	4.9	4.0	3.0	3.2	3.7	3.7	3.2	3.1	3.4
CPI ex. Food and Energy (nsa, d)	5.6	5.5	5.6	5.5	5.3	4.8	4.7	4.3	4.1	4.0	4.0	3.9
PCE Chain Price Index (d)	5.5	5.2	4.4	4.4	4.0	3.2	3.3	3.3	3.4	2.9	2.6	2.6
Core PCE Chain Price Index (d)	4.9	4.8	4.8	4.8	4.7	4.3	4.2	3.7	3.6	3.4	3.2	2.9
Producer Price Index (nsa, d)	5.7	4.7	2.7	2.3	1.1	0.3	1.1	1.9	2.0	1.2	0.8	1.0
Durable Goods Orders (a)	-1.3	-2.7	3.3	1.2	2.0	4.3	-5.6	-0.1	4.0	-5.1	5.5	0.0
Leading Economic Indicators (a)	-0.5	-0.6	-1.2	-0.7	-0.7	-0.7	-0.3	-0.4	-0.8	-1.0	-0.5	-0.1
Balance of Trade & Services (f)	-70.8	-70.6	-60.4	-72.9	-66.9	-64.0	-65.0	-58.6	-61.2	-64.5	-63.2	····
Federal Funds Rate (%)	4.33	4.57	4.65	4.83	5.06	5.08	5.12	5.33	5.33	5.33	5.33	5.33
3-Mo. Treasury Bill Rate (%)	4.69	4.79	4.86	5.07	5.31	5.42	5.49	5.56	5.56	5.60	5.52	5.44
10-Year Treasury Note Yield (%)	3.53	3.75	3.66	3.46	3.57	3.75	3.90	4.17	4.38	4.80	4.50	4.02

(a) month-over-month % change; (b) millions, saar; (c) month-over-month change, thousands; (d) year-over-year % change; (e) annualized % change; (f) $ billions; (g) level. Most series are subject to frequent government revisions. Use with care.

Calendar of Upcoming Economic Data Releases

Monday	Tuesday	Wednesday	Thursday	Friday
January 29 Texas Manufacturing Outlook Survey (Jan) Short-Term Energy Outlook (Dec)	**30** FHFA HPI (Nov) Case-Shiller HPI (Nov) JOLTS (Dec) BED (Q2) Consumer Confidence (Jan) Housing Vacancies (Q4) Texas Service Sector Outlook Survey (Jan) FOMC Meeting	**31** ADP Employment Report (Jan) Employment Cost Index (Q4) Chicago PMI (Jan) EIA Crude Oil Stocks Mortgage Applications FOMC Meeting	**February 1** Productivity & Costs (Q4) ISM Manufacturing (Jan & Rev) S&P Global Mfg PMI (Jan) Construction (Dec) Challenger Employment Report (Jan) Weekly Jobless Claims	**2** Employment Situation (Jan) Consumer Sentiment (Jan, Final) Manufacturers' Shipments, Inventories & Orders (Dec) BEA Auto and Truck Sales (Jan)
5 ISM Services PMI (Jan) S&P Global Services PMI (Jan) Senior Loan Officer Survey (Q1)	**6** Public Debt (Jan) Kansas City Fed Labor Market Conditions Indicators (Jan) Interest on Public Debt (Jan)	**7** International Trade (Dec) Transportation Services (Dec) Consumer Credit (Dec) Treasury Auction Allotments (Jan) EIA Crude Oil Stocks Mortgage Applications	**8** Wholesale Trade (Dec) CEO Confidence Survey (Q1) Housing Affordability (Dec) Weekly Jobless Claims	**9** Survey of Professional Forecasters (Q1) Seas Adj CPI Revisions Kansas City Financial Stress Index (Jan)
12 Monthly Treasury (Jan)	**13** CPI & Real Earnings (Jan) Cleveland Fed Median CPI (Jan) NFIB (Jan) OPEC Crude Oil Spot Prices (Jan)	**14** Seas Adj PPI Revisions EIA Crude Oil Stocks Mortgage Applications	**15** Import & Export Prices (Jan) Advance Retail Sales (Jan) IP & Capacity Utilization (Jan) MTIS (Dec) Philadelphia Fed Mfg Business Outlook Survey (Feb) Empire State Mfg Survey (Feb) Home Builders (Feb) TIC Data (Dec) Weekly Jobless Claims	**16** New Residential Construction (Jan) Producer Prices (Jan) Consumer Sentiment (Feb, Preliminary) Business Leaders Survey (Feb)
19 **PRESIDENTS' DAY ALL MARKETS CLOSED**	**20** Retail E-Commerce Sales (Q4) Philly Fed Nonmanufacturing Business Outlook (Feb) Dallas Fed Banking Conditions Survey (Feb) Composite Indexes (Jan)	**21** CEW (Q3)	**22** Adv Quarterly Services (Q4) Existing Home Sales (Jan) S&P Global Flash PMIs (Feb) Chicago Fed National Activity Index (Jan) EIA Crude Oil Stocks Mortgage Applications Weekly Jobless Claims	**23** Treasury Auction Allotments (Feb)
26 Final Building Permits (Jan) New Residential Sales (Jan) H.6 Money Stock (Jan) Texas Manufacturing Outlook Survey (Feb) NABE Outlook (Q1) Steel Imports for Consumption (Jan, Preliminary)	**27** Adv Durable Goods (Jan) FHFA HPI (Dec & Q4) Case Shiller HPI (Dec) Richmond Fed Mfg & Service Sector (Feb) Texas Service Sector Outlook Survey (Feb) Consumer Confidence (Feb)	**28** GDP (Q4, 2nd Estimate) Adv Trade & Inventories (Jan) EIA Crude Oil Stocks Mortgage Applications	**29** Personal Income (Jan) Agricultural Prices (Jan) Dallas Fed Trimmed Mean (Jan) Underlying NIPA Tables (Q4, 2nd Estimate) Chicago PMI (Feb) Kansas City Fed Manufacturing Survey (Feb) Pending Home Sales (Jan) Weekly Jobless Claims	**March 1** Construction (Jan) ISM Manufacturing (Feb) S&P Global Mfg PMI (Feb) Consumer Sentiment (Feb, Final) Strike Report (Feb)
4 BEA Auto and Truck Sales (Feb)	**5** ISM Services PMI (Feb) S&P Global Services PMI (Feb) Manufacturers' Shipments, Inventories & Orders (Jan)	**6** ADP Employment Report (Feb) Wholesale Trade (Jan) JOLTS (Jan) Public Debt (Feb) Interest on the Public Debt (Feb) EIA Crude Oil Stocks Mortgage Applications	**7** International Trade (Jan) Productivity & Costs (Q4) Treasury Auction Allotments (Feb) Financial Accounts (Q4) Consumer Credit (Jan) Challenger Employment (Feb) Weekly Jobless Claims	**8** Employment Situation (Feb)

BLUE CHIP FORECASTERS

CONTRIBUTORS TO DOMESTIC SURVEY

Action Economics, LLC, Boulder, CO
Michael Englund
Bank of America, New York, NY
Ethan Harris
Barclays, New York, NY
Marc Giannoni
BMO Capital Markets Economics, Toronto, Canada
Scott Anderson
BNP Paribas North America, New York, NY
Andrew Schneider
Chan Economics, New York, NY
Anthony Chan
Chmura Economics & Analytics, Richmond, VA
Christine Chmura and Xiaobing Shuai
Comerica, Dallas, TX
Bill Adams
Daiwa Capital Markets America, New York, NY
Michael Moran
DePrince & Associates, Murfreesburo, TN
Albert E. DePrince Jr.
Economist Intelligence Unit, New York, NY
Leo Abruzzese and Jan Friederich
EY- Parthenon, New York, NY
Gregory Daco
Fannie Mae, Washington, DC
Douglas Duncan
Georgia State University, Atlanta, GA
Rajeev Dhawan
GLC Financial Economics, Providence, RI
Gary L. Ciminero
Goldman, Sachs & Co., New York, NY
Jan Hatzius
KPMG, New York, NY
Diane Swonk
ING Financial Markets, London, England
James Knightley
J.P. Morgan Chase, New York, NY
Bruce Kasman
Loomis, Sayles & Company, L.P., Boston, MA
Brian Horrigan
MacroFin Analytics & Rutgers Business School, Wayne, NJ
Parul Jain
MacroPolicy Perspectives, New York, NY
Julia Coronado and Laura Rosner
Moody's Analytics, West Chester, PA
Mark M. Zandi
Naroff Economic LLC, Philadelphia, PA
Joel L. Naroff
NatWest Markets, Greenwich, CT
Kevin Cummins and Deepika Dayal
Nomura Securities International, Inc., New York, NY
U.S. Economics
Northern Trust Company, Chicago, IL
Carl Tannenbaum
Oxford Economics, New York, NY
Ryan Sweet
PNC Financial Services Group, Pittsburgh, PA
Gus Faucher
RDQ Economics, New York, NY
John Ryding and Conrad de Quadros
Regions Financial Corporation, Birmingham, AL
Richard F. Moody
Roberts Capital Advisors, Denver, CO
Michael Roberts
Santander Capital Markets, New York, NY
Stephen Stanley
Scotiabank Group, Toronto, Canada
Jean-Francois Perrault
Societe Generale, New York, NY
Stephen W. Gallagher
S&P Global Market Intelligence, St. Louis, MO
Joel Prakken & Chris Varvares
Swiss Re, New York, NY
Jerome Haegeli
The Lonski Group, White Plains, NY
John Lonski
TS Lombard, London, UK
Steven Blitz
Via Nova Investment Management, Crozet, VA
Alan Gayle
Wells Fargo, Charlotte, NC
Jay Bryson

CONTRIBUTORS TO INTERNATIONAL SURVEY

Barclays Capital, New York, NY
BMO Capital Markets Economics, Toronto, Canada
ING Financial Markets, London, England
Moody's Analytics, West Chester, PA
Nomura Securities International, Inc., New York, NY
Northern Trust Company, Chicago, IL
Oxford Economics, Wayne, PA
Scotiabank Group, Toronto, Canada
S&P Global Market Intelligence, St. Louis, MO
TS Lombard, London, UK
Wells Fargo, Charlotte, NC

Markets

Wall Street Is Rethinking the Treasury Threat to Big Tech Stocks

By Justina Lee
March 11, 2021, 10:08 AM EST

- Investors fear sector has morphed into a big bet on low rates
- Yet history shows tech's link with bonds is far more complex

Don't fear Treasury yields killing off the stock market's golden goose just yet.

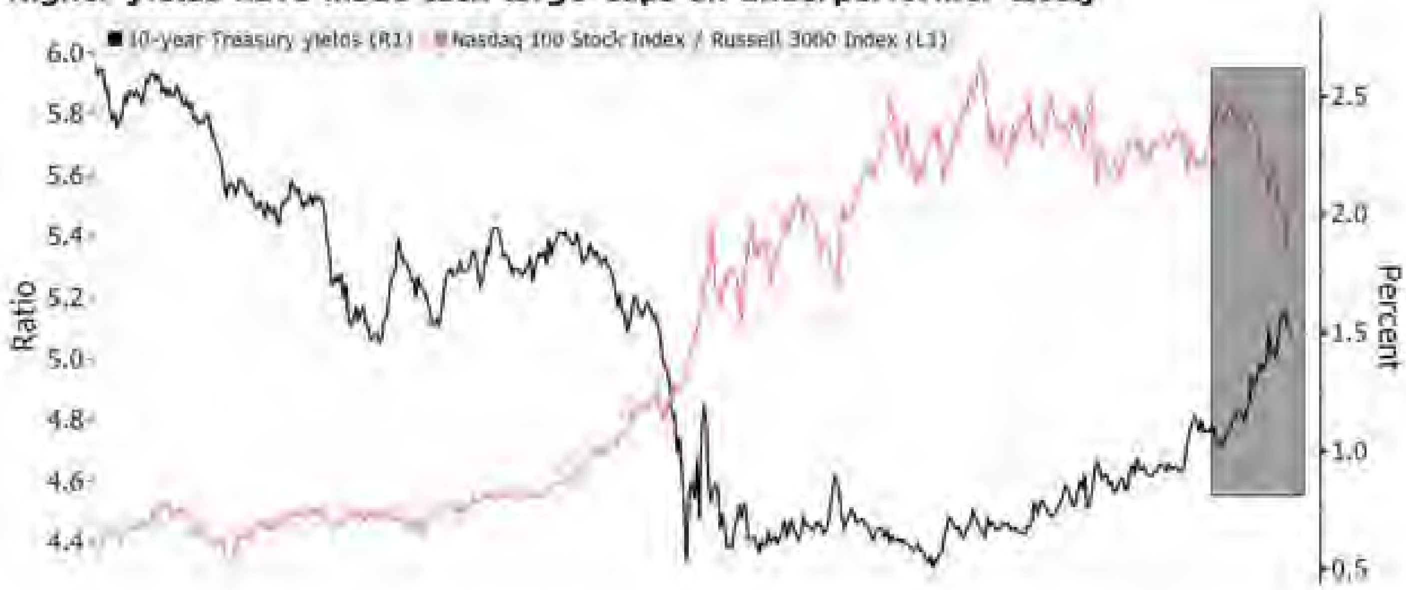
As the Nasdaq 100 Index recovers from a $1.5 trillion rout, there's good reason to think technology shares can defy machinations in U.S. bonds.

Studies from Deutsche Bank AG and Goldman Sachs Group Inc. show the world's biggest equity sector has a fickle relationship with Treasuries, if it has one at all. Quant powerhouse AQR Capital Management has found little evidence that yields drive how expensive megacaps trade relative to their cheaper counterparts.

And of course, secular economic trends have been powering the likes of Facebook Inc. and Amazon.com Inc. for years now -- when benchmark rates were far higher than current levels.

All that makes the Treasury-stock link more complex than it seems.

Low-Rate Trade?
Higher yields have made tech large-caps an underperformer lately



Source: Bloomberg

Put another way, while the recent Treasury selloff has pummeled Big Tech, that doesn't mean bonds are a natural foe for a sector hitched to secular trends from 5G to automation.

"Many tech companies will continue to benefit for many years from very strong themes that will result in outsized earnings growth," said Terry Ewing, head of equities at Mediolanum International Funds, which oversees about $54 billion. "The dilemma for portfolio managers running a balanced mandate is that actually the de-rating we've seen in growth stocks has put them at a much more attractive level."

Ewing's funds began offloading a handful of tech stocks for cyclical names from the third quarter, just as rising expectations for an economic re-opening pushed yields higher in the world's biggest bond market.

As the U.S. yield curve steepened last month, $1.5 trillion of value was wiped off tech shares, while assets deemed less sensitive to duration risk like value stocks -- banks, oil drillers and commodity producers -- surged.

The Nasdaq 100 jumped nearly 2% on Thursday morning in New York, as 10-year Treasury yields traded little changed around 1.5%.

Quant Perspective

From the perspective of quants who dissect equities by their factors, there are a few ways to explain the last month's rotation.

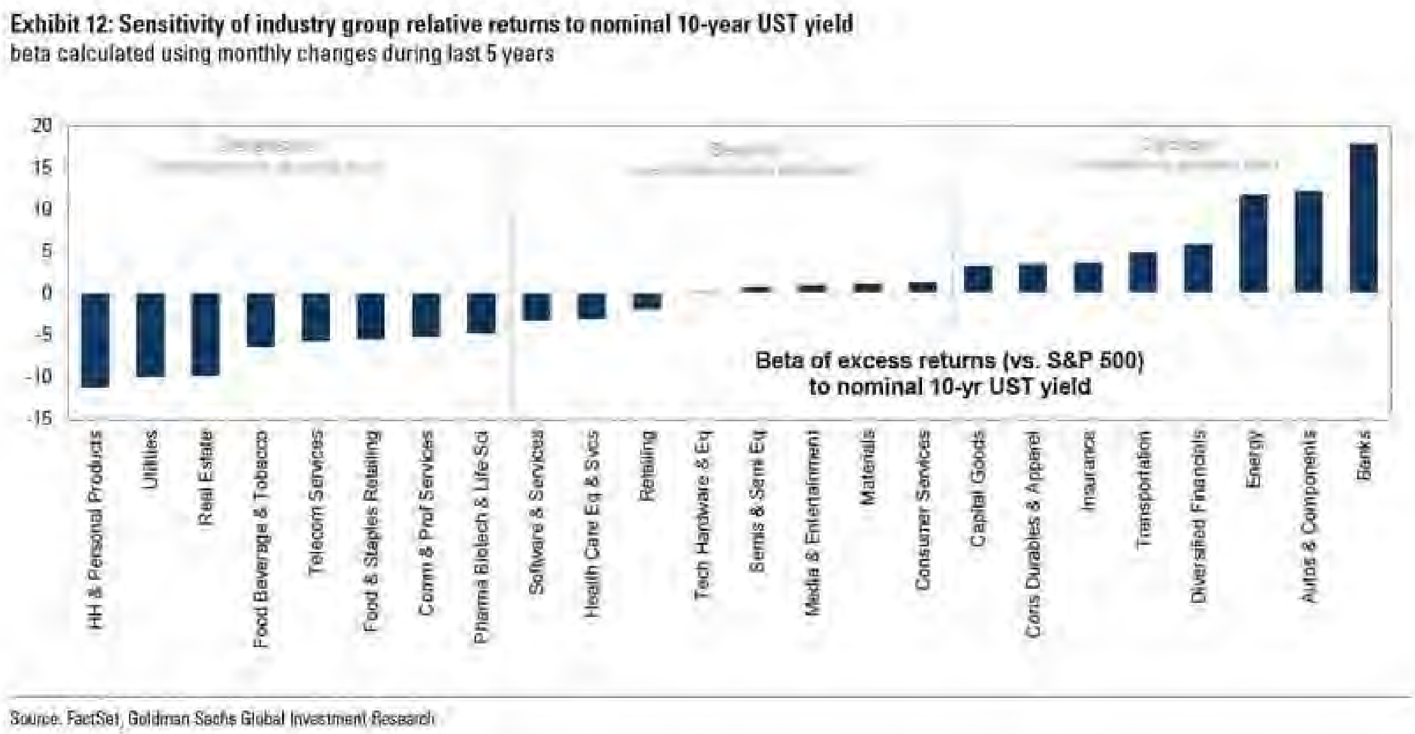
Technology companies are typically dubbed growth stocks thanks to their strong expected profit expansion, often far into the future. That's in contrast to value shares, which trade with lower multiples due to their riskier businesses.

When rates fall, economic growth is typically muted. That makes a company like Netflix Inc. look like a a safer bet since it's riding the secular trend of streaming rather than ups and downs of the business cycle. Meanwhile the likes of Exxon Mobil Corp., tied to oil demand, look riskier.

In the post-crisis era of monetary easing, that's how the valuation dynamic played out: Netflix's long-term earnings were discounted at lower rates -- making it more expensive.

Now, opposing forces are in play. Rising yields are making the near-term cash flows of cheaper equities like Exxon Mobil more attractive.

"Sooner or later we will see pretty decent economic growth," said Georg Elsaesser, a quant portfolio manager at Invesco. "I would be more than surprised if that wouldn't be favorable for high-risk factors like value."



Source: Goldman Sachs

Yet all these relationships are volatile -- and have far less explanatory power than commonly asserted.

Interest-rate changes only explain 19% of the returns posted by the growth factor versus value since 2018, Goldman Sachs strategists wrote in a note last month. That compares with 54% for cyclicals versus defensive.

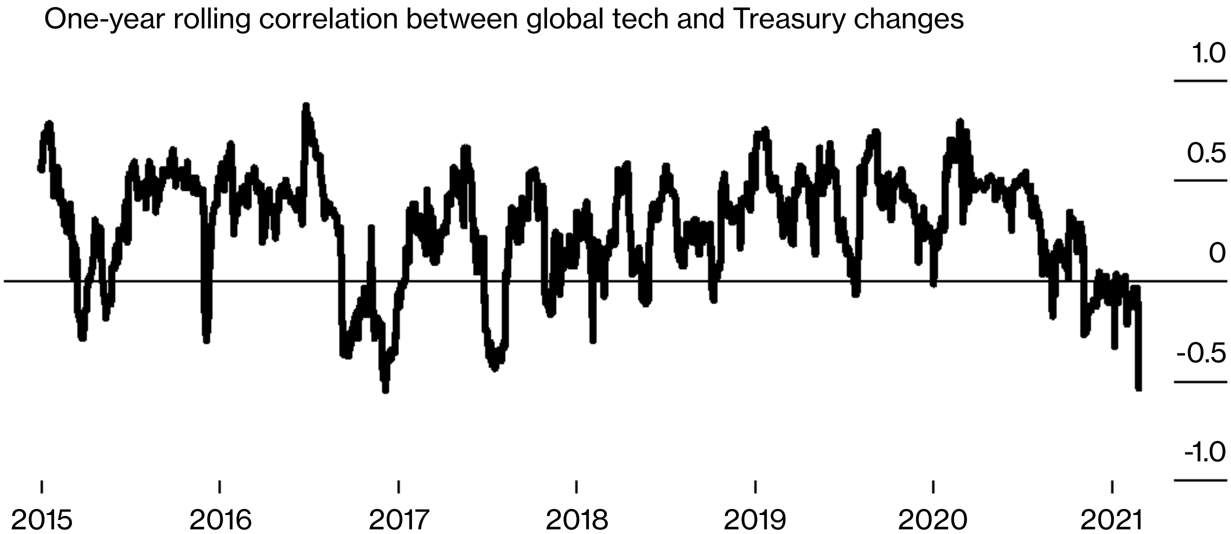
In other words, industry-specific trends, not bonds, seem to be driving this tech-heavy part of the market.

Similarly Deutsche Bank's quants find a zero beta, or sensitivity, between bonds and tech since 2015. In contrast, financials and energy had the most positive links with yields, and utilities and real estate the most negative.

According to Andreas Farmakas, a quantitative strategist at Deutsche Bank, this shows how the tech sector and Treasuries lack a direct and consistent link. In fact, these stocks in the past often rose with rates, with the latter seen as a sign of economic strength that could benefit corporate earnings.

It's Complicated

Tech stocks' relationship with Treasuries has been volatile in the short run



Source: Deutsche Bank
Data show one-year rolling correlation between daily moves in global tech and in 10-year Treasury yields

That's not to say there isn't reason to fret recent co-movements.

"Given the ties between technology, the overbought Covid trade and ultimately equity indices -- they take up a large chunk -- the correlation flipped," Farmakas said.

In other words, bonds have lately turned from friend to foe -- and that's why quants like Invesco's Elsaesser are so reluctant to time markets.

For its part, AQR last year called the link between interest rates and value -- which involves a bet against growth -- "suspect" since it varies greatly depending on the period, the markets and measurements studied.

All this suggests that once the initial reflation frenzy settles, there's no reason to fear bond yields will necessarily doom the tech trade. In fact Ewing at Mediolanum is eyeing some bargains in the months ahead.

"Somewhere along the second-half of this year going into next year it'll be prudent for investors to start considering moving to higher-quality names rather than cyclical recovery," he said.

In this article

GS
GOLDMAN SACHS GP
343.12 USD ▲ +1.10 +0.32%

DBK
DEUTSCHE BANK-RG
10.52 EUR ▼ -0.20 -1.88%

CL1
WTI Crude
65.45 USD/bbl. ▲ +1.01 +1.57%

NFLX
NETFLIX INC
512.64 USD ▲ +8.10 +1.60%

XOM
EXXON MOBIL CORP
62.46 USD ▲ +0.69 +1.11%

UBS prefers info tech, consumer staples and energy in 2024

Dec. 12, 2023 11:19 AM ET | **S&P 500 Index (SP500)** | XLU, XLE, XLV... | By: Jason Capul, SA News Editor

Fabrice Cabaud

UBS predicted Tuesday that info tech, consumer staples and energy would be the most preferred sectors for 2024. The firm added that a soft landing is being priced into the market, with the recent market rally being fueled by the idea that the Federal Reserve is done hiking.

Furthermore, UBS noted that cooling inflation data and labor market conditions have also been driving catalysts. Turning to 2024, the firm said: "We think earnings growth can accelerate in 2024 despite slowing GDP growth due to base effects in healthcare and energy as well as a moderate improvement in the goods side of the economy."

"Although earnings revision breadth is weakening, the forward S&P 500 EPS estimate continues to climb," UBS added.

See the highlighted sectors of the economy below that the investment bank views as most preferred, least preferred, and neutral.

Most Preferred

Consumer Staples (XLP)

Energy (XLE)

Information Technology (XLK)

Neutral

Communication Services (XLC)

Consumer Discretionary (XLY)

Financials (XLF)

Healthcare (XLV)

- Industrials (XLI)

Least Preferred

- Materials (XLB)
- Real Estate (XLRE)
- Utilities (XLU)

Moreover, the financial institution also provided its investors with some S&P 500 (SP500) targets. The financial institution provided a target of 4,500 for June of 2024 and 4,700 for the benchmark index as of December 2024.

More on Markets

- China: Opportunities and risks - FTSE Russell
- New thematic ETF issuer launches funds for airline, cybersecurity and AI sectors
- Top 10 exchange traded fund outflow leaders in 2023
- 2024 Analyst Outlook: JR Research On Growth/Tech Stocks, Sector Rotation, And Market Trends

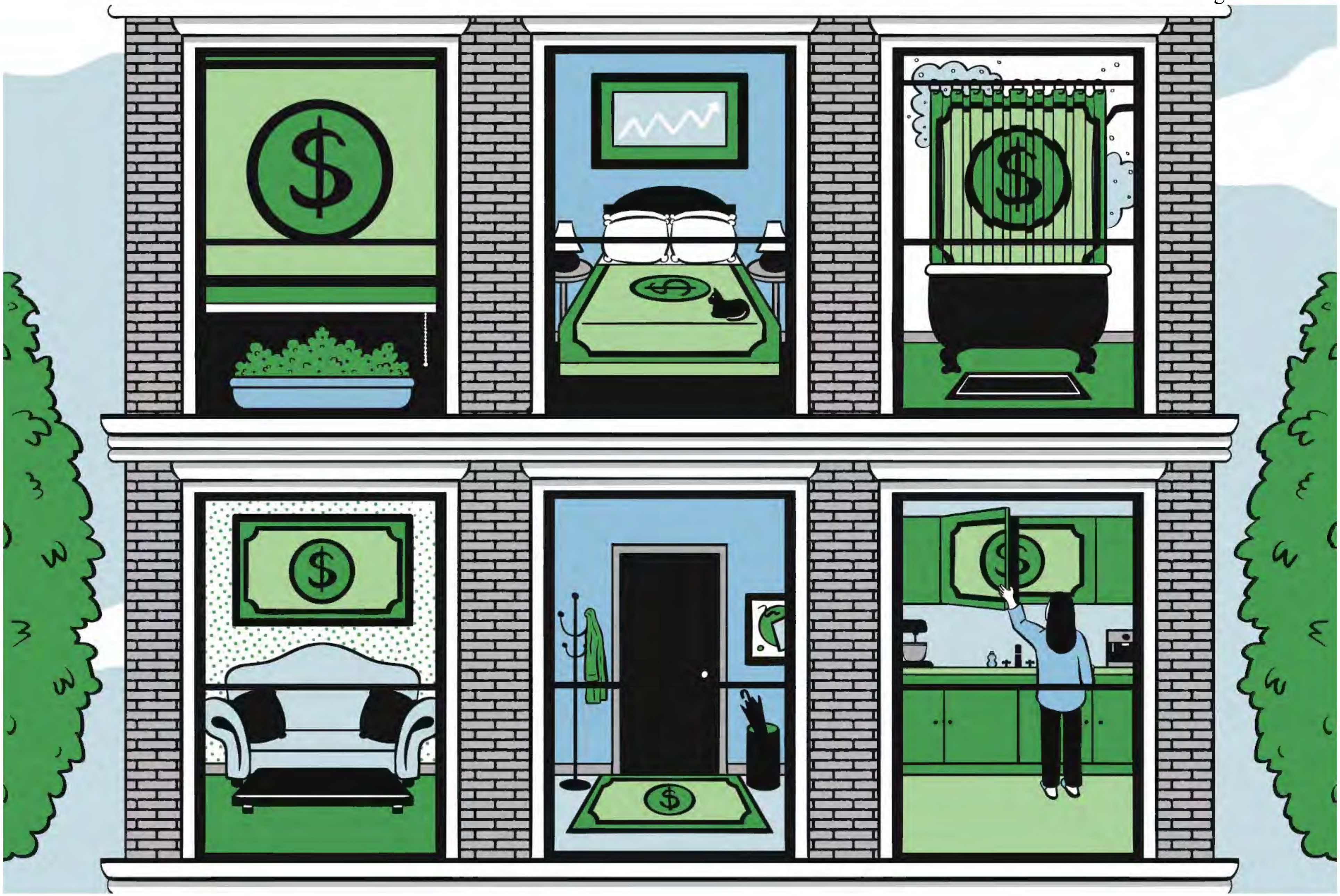


ILLUSTRATION BY MELANIE LAMBRICK

EXCLUSIVE

Big Money Pros Are Split on the Outlook for Stocks. But They Are Fans of Bonds.

Nearly half of poll respondents consider the U.S. stock market overvalued at current levels.

By Nicholas Jasinski Follow

Updated October 27, 2023 / Original October 27, 2023

This year has posed an unusual array of challenges for investors, and more could be in store. The major stock market indexes are still up in 2023, powered by a narrow slice of technology stocks, but have been losing ground rapidly. Bond yields have risen sharply, topping 5% on some government debt. The economic outlook is uncertain, the U.S. government has been in turmoil, and wars and conflict are spreading across the globe.

"Rarely have I seen such disarray in the world, with financial markets, politically, and otherwise," says William Priest, executive chairman and co-chief investment officer at Epoch Investment Partners in New York, and a respondent to our fall 2023 Big Money poll.

This fall, there is no predominant mood among the professional money managers surveyed by Barron's. Some 38% of Big Money respondents say they are bullish about the prospects for equities in the next 12 months. That compares with 38% in the neutral camp, and 24% who call themselves bears.

The bulls see a 14% rise for the S&P 500 index by the end of 2024, and a 12% gain by the Dow Jones Industrial Average. The bears forecast losses of 3% for the S&P 500 and 2% for the Dow.

Based on their mean forecasts, the bulls project a 15% gain by the end of 2024 for the Nasdaq Composite, while the bears expect the tech-heavy Nasdaq to decline 4%.

The latest Big Money Poll closed on Oct. 13 and elicited responses from more than 100 professional investors from across the country. Barron's conducted the poll with the help of Erdos Media Research in Ramsey, N.J. (Complete results are at the bottom of this article.)

High-quality bonds and value stocks have the most fans in our survey. Investors expect a tough year ahead for the more growth-oriented areas of the stock market. Nearly half of poll respondents consider the U.S. stock market overvalued at current levels.

One reason is the recent ramp-up in bond yields, which raises the competition for equities. The Federal Reserve's policy committee has increased its interest-rate target by more than five percentage points in the past 19 months to cool the economy and bring down inflation, while market forces have pushed up yields on long-term bonds. The yield on the benchmark 10-year U.S. Treasury note approached 5% this month, up from a paltry 0.5% at its pandemic-era low.

Yields along the Treasury curve are at their highest levels since before the global financial crisis of 2008-09. It's a return to the pre-2008 world as far as investors are concerned—not the low-growth, low-interest-rate, low-inflation, growth-stock-dominated decade that ended in 2022, two years after the start of the Covid-19 pandemic.

"The single most important variable in investing is interest rates," says Priest, a member of the Barron's Roundtable, whose firm manages about $28 billion. "Earnings may be fine next year and beyond, but it's the present value of those numbers that's going to be the problem."

Two-thirds of Big Money respondents say value investing will outperform growth-stock investing in the next 12 months.

And a majority of Big Money investors predict bonds will provide a higher return than stocks in the coming 12 months. While bonds have become cheaper this year (prices move inversely to yields), stocks remain relatively expensive: The S&P 500 trades for 17 times analysts'

2024 consensus earnings estimate.

On average, Big Money respondents have allocated about 20% of their portfolios to fixed income today. “We like bonds, especially when looking at equities that are trading at above-average [valuation] multiples,” says Matt Dmytryszyn, chief investment officer at Telemus Capital, with $3.5 billion in assets under management. “It has been a while since we’ve been able to get this excited about bonds.”

Fixed income might be in greater favor now, but few money managers expect a lost half-decade for U.S. stocks. Indeed, 95% expect to reap a higher return from stocks than bonds in the next five years.

Among fixed-income categories, 40% of managers prefer U.S. Treasuries. They have little credit risk, and yields are at 16-year highs. Another 24% like U.S. investment-grade corporate bonds. Spreads—or the premium yield on riskier bonds over Treasuries or another benchmark—are narrow, given the potential for a recession in 2024, which argues for favoring higher credit quality.

Big Money managers don’t have much duration risk in their portfolios, or sensitivity to changing interest rates. An average of 61% of their fixed-income exposure is in short-term securities maturing in less than three years, and just 8% is in bonds maturing in more than 10 years.

“We’re not sticking our neck out too much on a duration basis,” says Zach Jonson, CIO at Stack Financial Management in Whitefish, Mont. “An inflation spike or some kind of stagflation can happen, and you just have to be more careful than you normally would with duration.”

It’s hard to argue with yields pushing 5.6% on T-bills or 5.1% on the two-year U.S. Treasury note. As for where to park cash, short-term U.S. government bonds and money-market funds are best, according to the survey results.

Nearly two-thirds of Big Money respondents expect the 10-year Treasury note to yield at least 4.5% a year from now, versus a recent 4.8%. The yield still might rise a bit more before trending lower, some respondents say, while noting that it is at, or close to, levels at which locking in yields for the longer term makes sense.

“If we can get a Treasury yielding 5% or above for a decade, that’s pretty darn attractive,” says Jack DeGan, CIO at Harbor Advisory in Portsmouth, N.H. “We haven’t seen that opportunity in portfolios for a long time.”

There is also value in longer-term bonds as a hedge against broader market declines. A broad flight to safety among investors would push bond prices up and yields down.

Investors are split on the odds of a recession in 2024. Some give the

Federal Reserve ample credit for managing inflation down without sacrificing the economy, and see a so-called soft landing next year. Others are less sanguine, however, arguing that the impact of higher interest rates has yet to fully hit the real economy and that a recession is a question of when, not if.

Forty-six percent of respondents expect the economy to enter a recession in the next 12 months. But it needn't be a crisis-level downturn: Just 6% of investors expect U.S. real gross domestic product to contract by 2% or more next year.

"It's really hard to generate a big recession when there's that much money flowing into the economy," says Harbor's DeGan, pointing to pandemic-era stimulus spending and newer government programs such as the Infrastructure Investment and Jobs Act. "The Fed has raised interest rates dramatically, but our economy is less interest-rate sensitive than it has been in my 40 years in business."

Both consumers' and businesses' balance sheets are in good shape, he says, supporting spending but adding to the upward pressure on inflation. Only 15% of Big Money respondents expect inflation, as measured by the consumer price index, to come in at or below the Fed's 2% target in 2024. Most see the CPI hanging around 4% this year and slipping to 3% in 2024.

David Poarch, of Native American Fund Advisors in Tulsa, Okla., is concerned about sticky or potentially reaccelerating inflation, noting the trillions of dollars of monetary and fiscal stimulus pumped into the economy during and since the Covid pandemic. That flood of money is still working its way through the real economy, he says, despite the Fed's rate hikes over the past year and a half. "It's like the python that ate the pig—the economy needs some time to digest it," Poarch says.

Stack Financial's Jonson points to several long-term trends that are inherently inflationary, including the so-called reshoring of supply chains, the costly transition to renewable energy, and aging demographics that are leading to a shortage of labor in many developed markets.

What is the biggest risk facing the stock market? Twenty-eight percent of managers worry most about a potential recession, 26% point to the possibility of higher interest rates, and 16% cite resurgent inflation. This highlights the delicacy of the Federal Reserve's balancing act. The central bank must tap the brakes on the economy enough to ease the upward pressure on inflation, but not so much as to break things and cause a significant recession.

"The Fed is right to be proactive and [keep rates] higher for longer, so that inflation doesn't come back," says Dmytryszyn of Telemus

Capital, headquartered in Southfield, Mich.

Most Big Money managers approve of the Fed's moves to date, with 62% saying its current policy stance is just right. But half that percentage thinks the Fed has tightened too much and risks pushing the economy into a recession.

Nearly all survey respondents think the Fed is just about done raising interest rates, and that rate cuts could be coming next year. More than 80% predict that Fed officials will lower the current federal-funds target range of 5.25% to 5.50% next year by at least a quarter of a percentage point, while 35% expect rate cuts of more than half a point.

Joe Frohna, founding principal and portfolio manager at 1492 Capital Management, based in Milwaukee, notes that the Fed's first rate decrease of a cycle historically has followed the central bank's last hike by an average of 7.5 months. That pattern implies a rate cut sometime around the middle of next year.

"For the stock and bond markets to work in 2024, you're going to need the Fed to step out of the way," says Frohna. "At a minimum, that means they say they're pausing, if not [cutting] outright."

Broader participation in the market beyond the largest stocks would help to extend any rally. The S&P 500's 9% gain year to date is almost entirely due to advances in a handful of megacap tech stocks including Apple (ticker: AAPL), Nvidia (NVDA), Microsoft (MSFT), and Alphabet (GOOGL).

“It’s hard to get excited about a rally when it’s being led by such a narrow group,” says Todd Jones, CIO of Gratus Capital in Atlanta, with about $3 billion in assets. “The valuations of the top 10 companies in the S&P 500 are super-elevated versus bottom 490.”

About 60% of Big Money respondents expect small- or mid-cap stocks to outperform large-caps over the next 12 months. The iShares Core S&P Small-Cap exchange-traded fund (IJR) and the SPDR S&P MidCap 400 ETF (MDY) are ways to play the market’s smaller stocks.

Weatherly Asset Management’s Carolyn Taylor is sticking with Big Tech stocks for now, and waiting for better opportunities to present themselves. These companies have pristine balance sheets and wide competitive moats, and generate a ton of free cash flow, she notes. Should rates fall, however, more-speculative areas in the technology sector could become more attractive, namely shares of the fast-growing but richly valued companies expected to generate the bulk of their profits far in the future.

“We have dry powder in the form of cash and short-term fixed income and are a bit lighter than usual on equities,” says Taylor, whose Del

Mar, Calif.–based firm manages about $1.2 billion. “So, if we do have a recession and the Fed starts to cut interest rates, we have the ability to shift.”

Epoch’s Priest is also bullish on Microsoft and Alphabet, both plays on 2023’s hottest investing theme: artificial intelligence. “They’re going to win with AI,” he says. “From a long-term investment perspective, you want to be exposed to those.”

Nvidia stock has rallied more than 175% this year, also fueled by enthusiasm for AI. But the stock isn’t so popular with the Big Money crowd: 29% of managers call it the market’s most overvalued stock. Nvidia sports a price/earnings ratio of 27 times the next year’s estimated earnings.

Energy stocks are Big Money investors’ favorite sector for the year ahead, designated as such by 33% of respondents. They like the sector for its relatively discounted valuation, high cash-flow yields, and generous dividend and share-buyback policies. Exposure to a potential spike in oil and gas prices also makes energy a defensive play.

Poll respondents see West Texas Intermediate, the U.S. benchmark oil price, rising to $91 a barrel in a year from the mid-$80s today. “Energy is both cheap and attractive as a hedge,” says Jonson, whose firm has about $1.8 billion in assets under management.

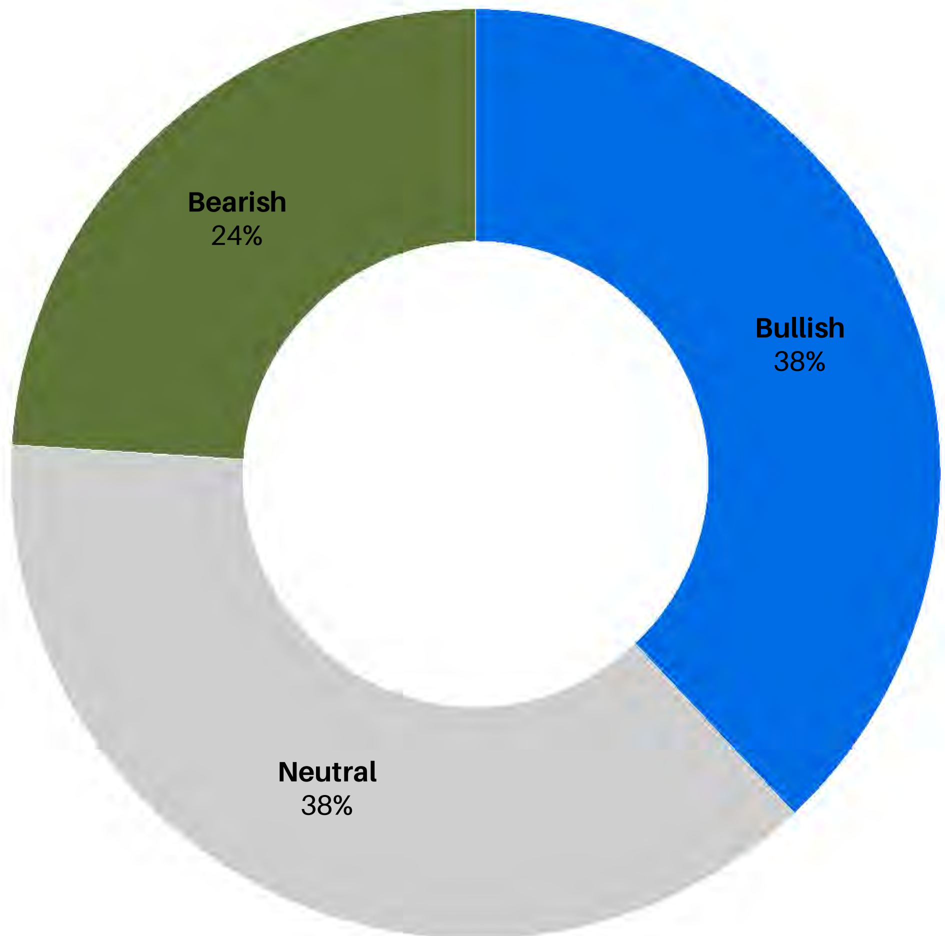
Gratus' Jones also likes midstream energy companies for their dividends and contractual cash flows tied to the volume of oil and natural gas that flows through their pipelines. Midstream companies include Williams Cos. (WMB), which yields 5.2%; Oneok (OKE), yielding 5.7%; and Kinder Morgan (KMI), yielding 6.7%.

Higher interest rates and bond yields have weighed on other income-generating assets, including dividend stocks. DeGan sees opportunities in the shares of quality companies with durable businesses that have seen their valuations fall and dividend yields rise this year. He points to Brookfield Infrastructure Partners (BIP), with a 6.7% yield; Pfizer (PFE), paying 5.4%; and NextEra Energy (NEE), yielding 3.4%.

Plenty could go wrong for the markets and world in the next year. For investors in stocks and bonds, a focus on attractive yields and undervalued assets seems like a sensible game plan.

The Markets

Describe your investment outlook for U.S. equities in the next 12 months.

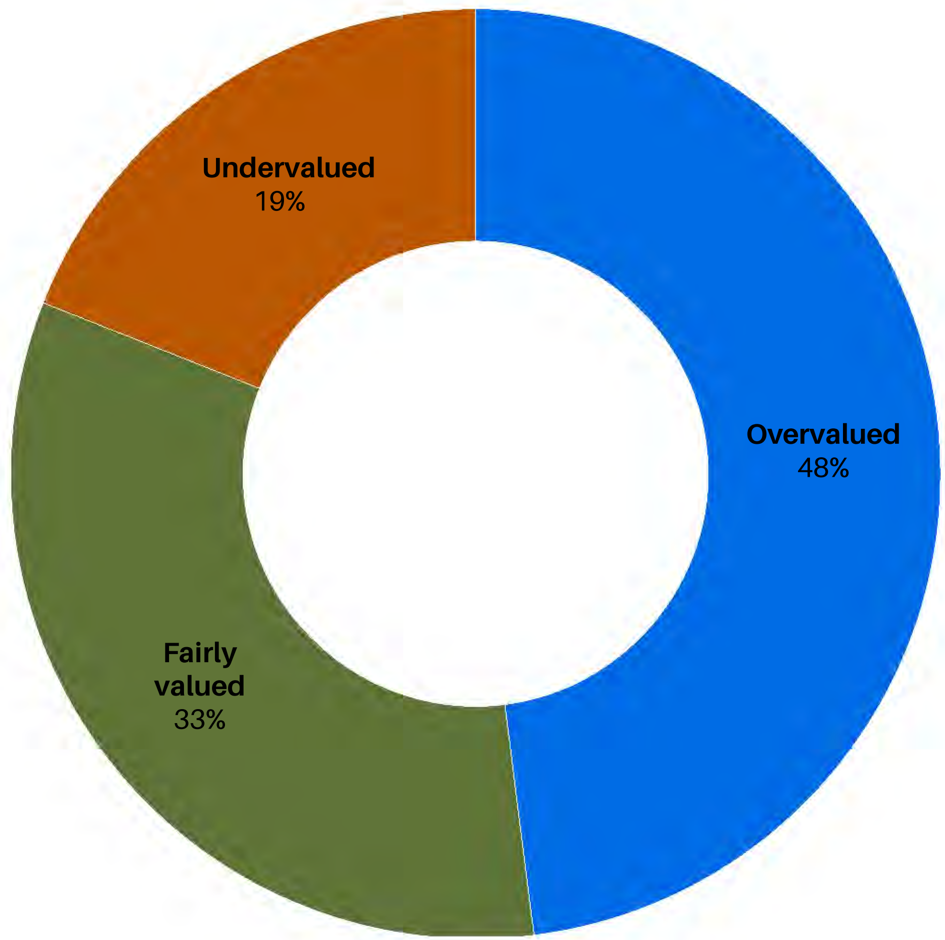


Where do you expect the following market measures to trade as of June 30, 2024, and Dec. 31, 2024?

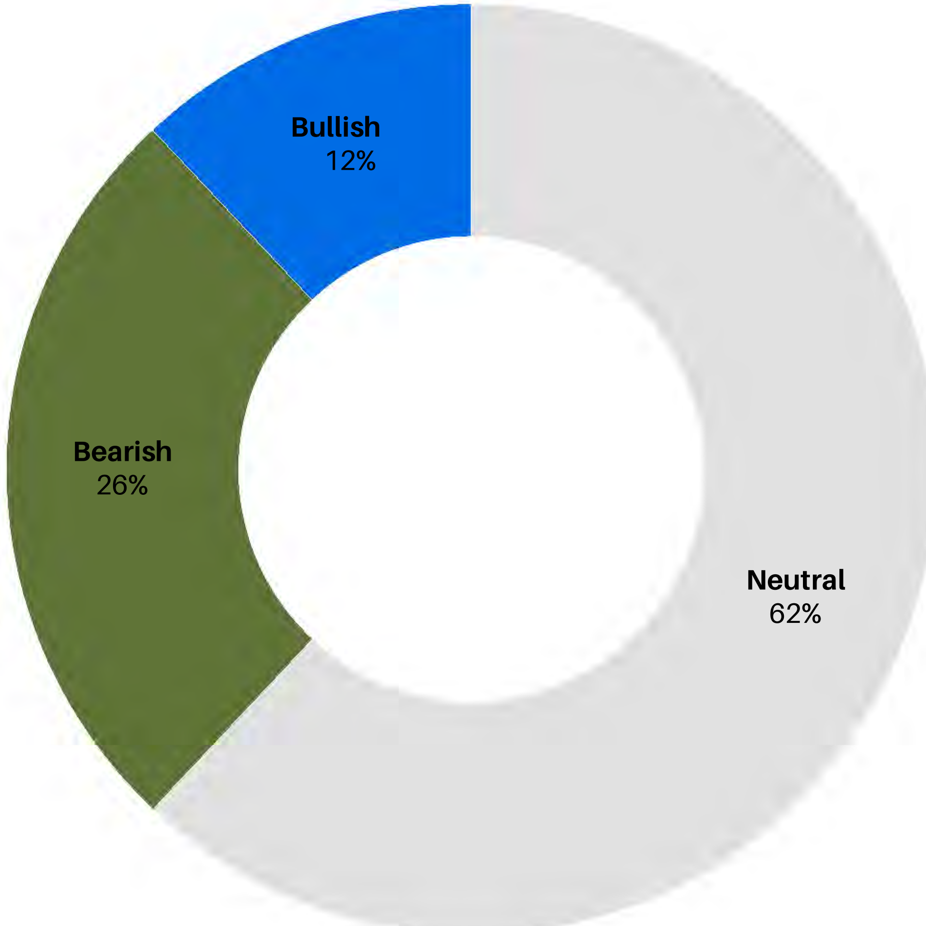
BULLISH	6/30/2024	12/31/2024
DJIA	35,563	36,923
S&P 500	4583	4760
Nasdaq	13,944	14,521

BEARISH	6/30/24	12/31/24
DJIA	31,300	32,179
S&P 500	3949	4037
Nasdaq	11,741	12,123

Is the U.S. stock market overvalued, undervalued, or fairly valued at current levels?



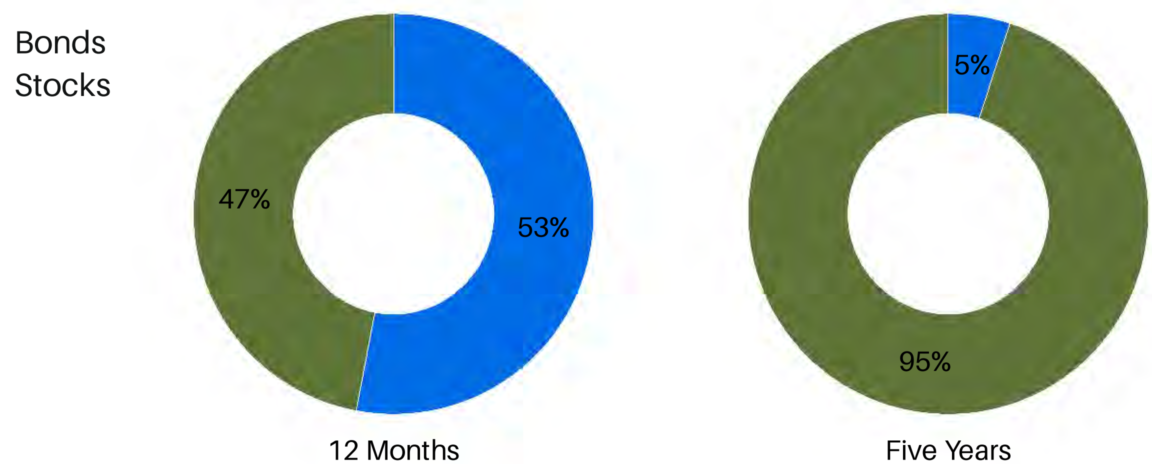
Are your clients bullish, bearish, or neutral about U.S. stocks?



What is the biggest risk the stock market will face in the next six months?

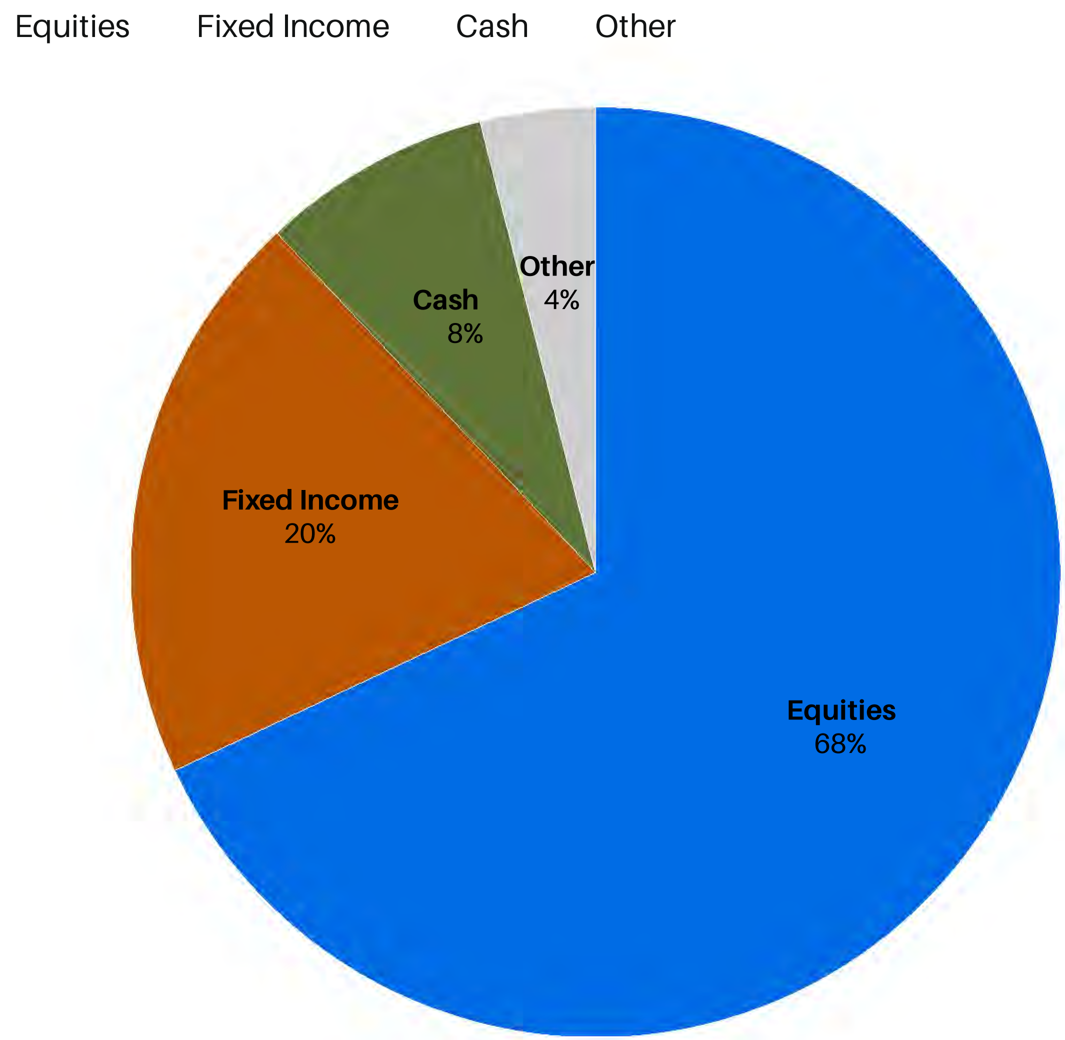
Economic slowdown / recession	28%
Higher interest rates	26%
Resurgent inflation	16%
Systemic financial problems	7%
Geopolitical turmoil	6%
Other	17%

Which asset class will provide a higher return in the next 12 months? The next five years?

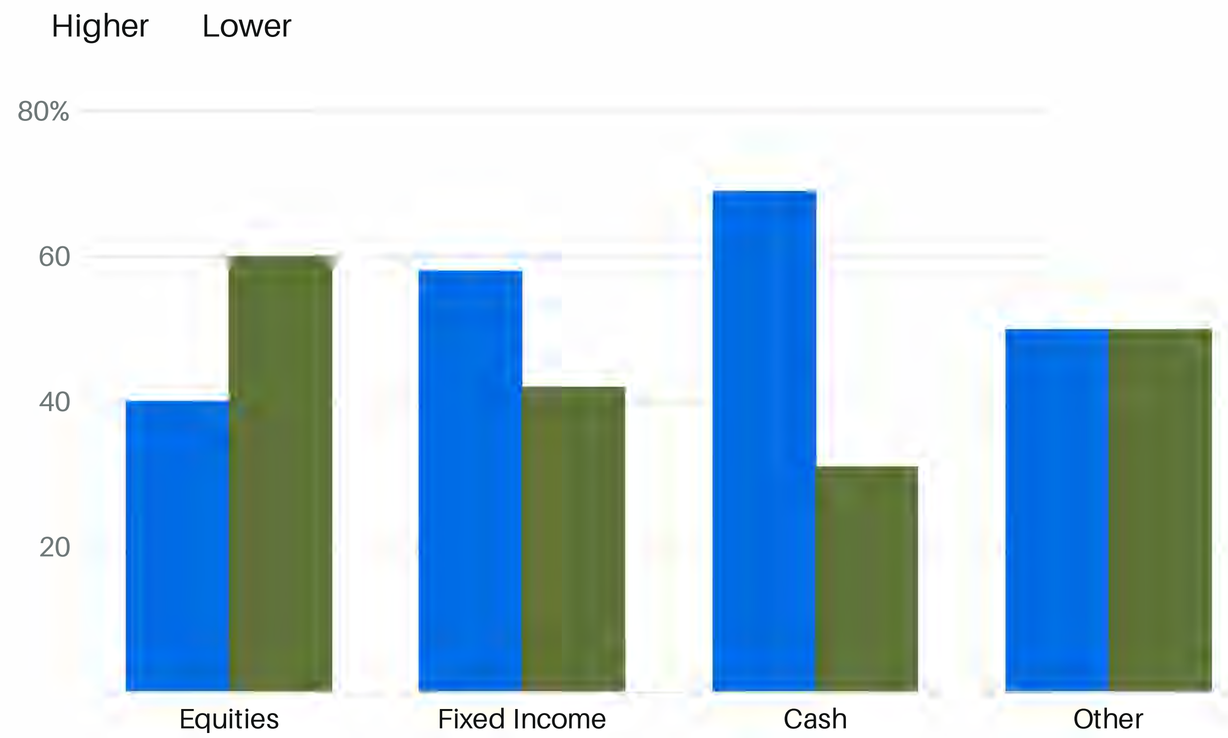


Investing

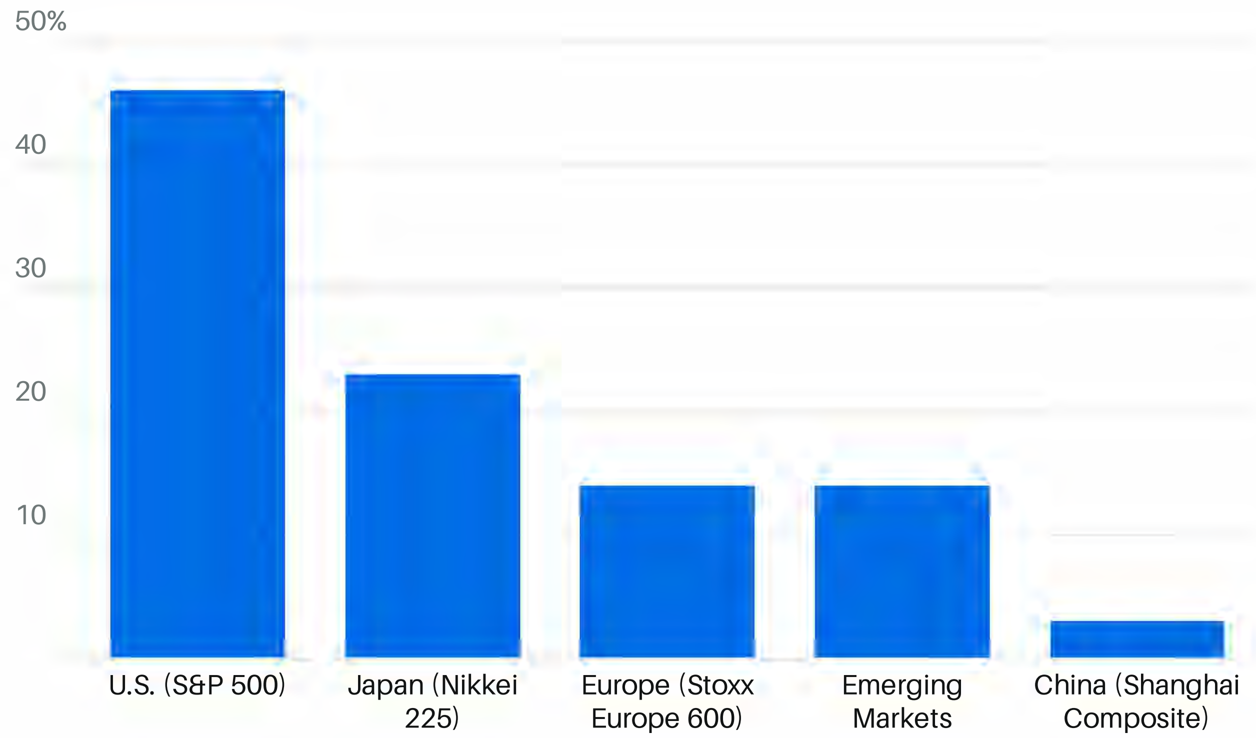
Describe your current asset allocation.



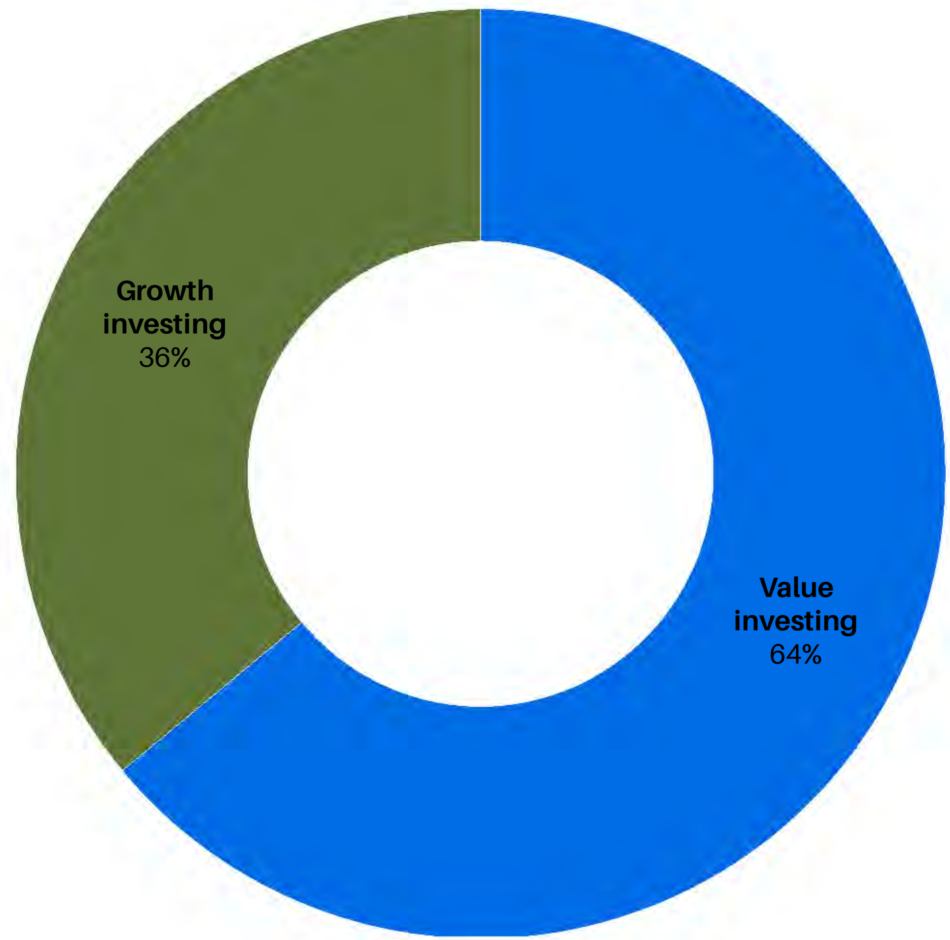
Is your weighting in each of these assets higher or lower than six months ago?



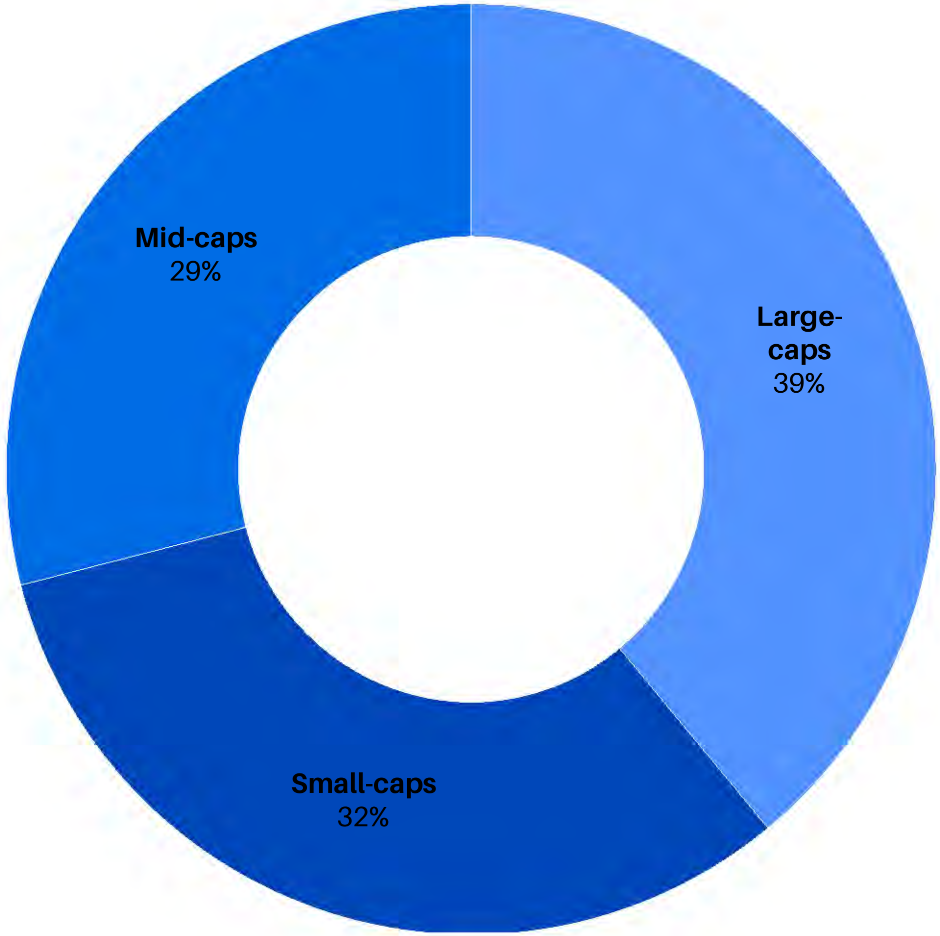
Which major equity market will perform best in the next 12 months?



Which investment approach will perform best in the next 12 months?

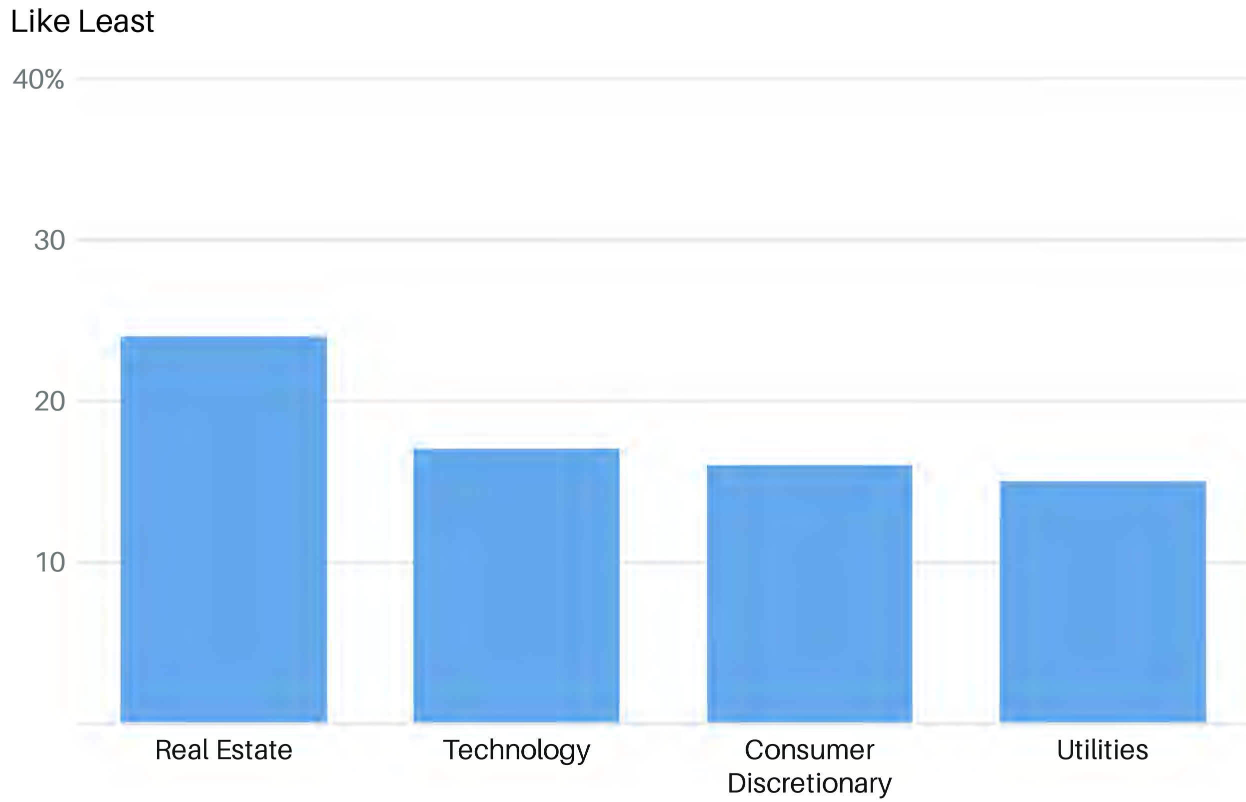


Which equity category will perform best in the next 12 months?

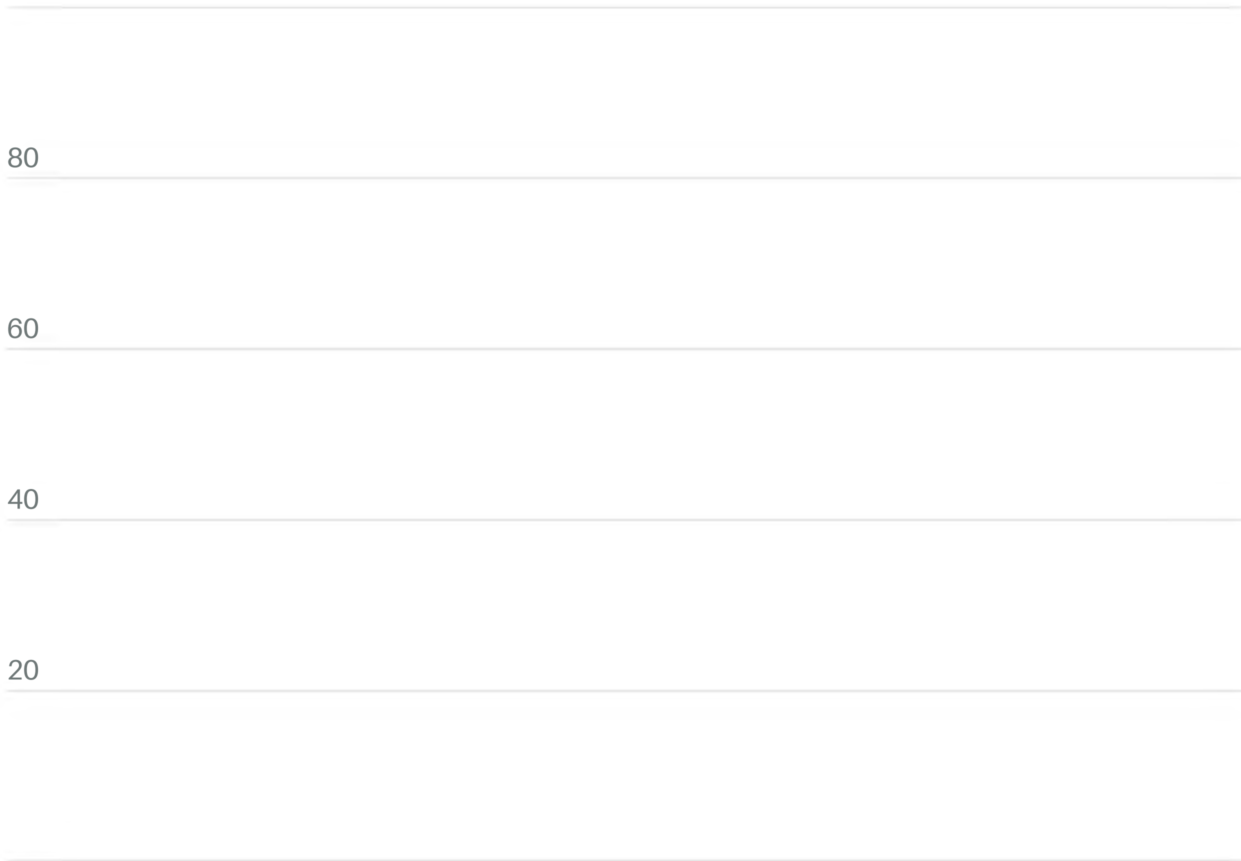


Which equity sector do you currently like most, and which do you like least?

Like Most

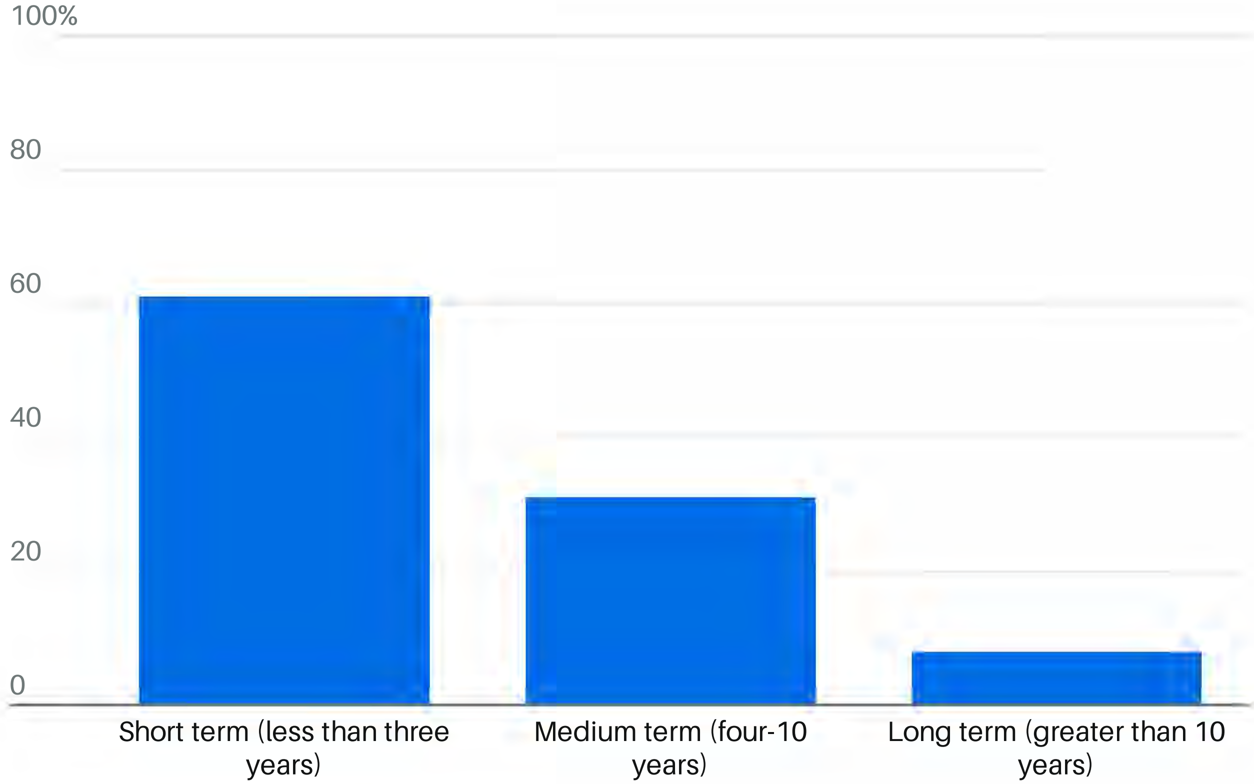

Like Least
40%
30
20
10
Real Estate
Technology
Consumer Discretionary
Utilities

Which fixed-income category do you currently favor most?



*Treasury Inflation-protected Securities

Describe your fixed-income allocation by duration.



Where is the best place to park cash right now?

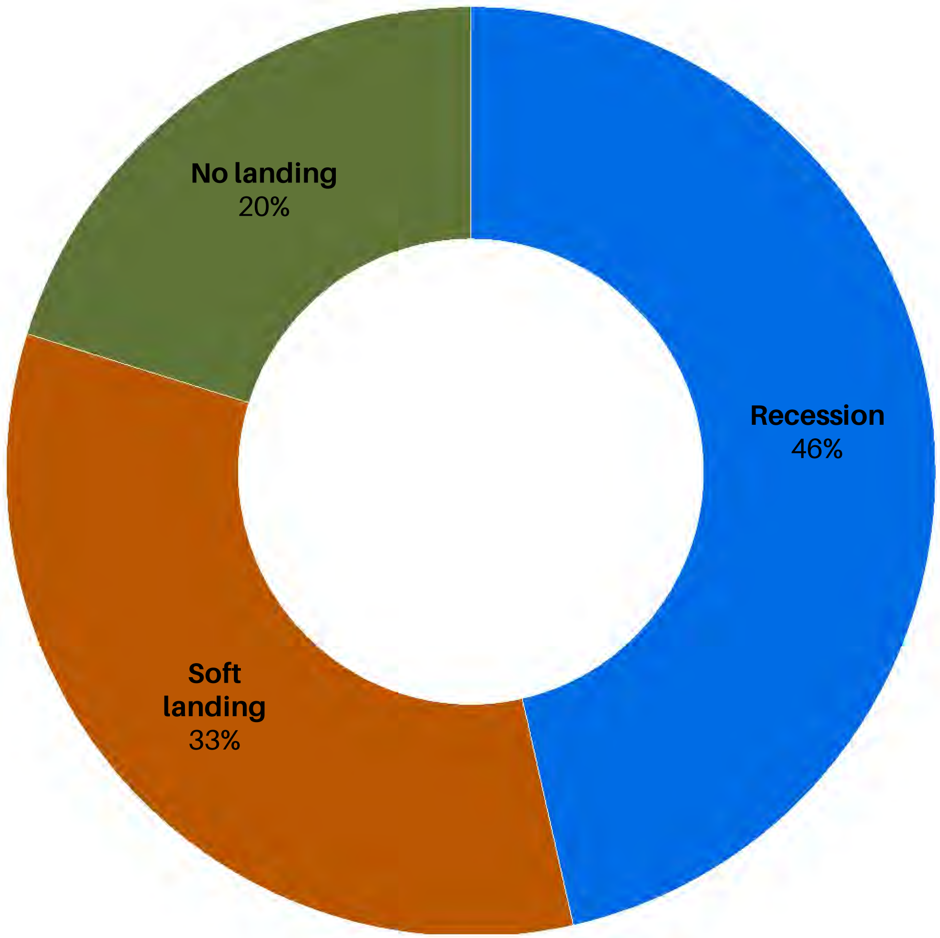
Prediction

Predict the levels of the following one year from now.

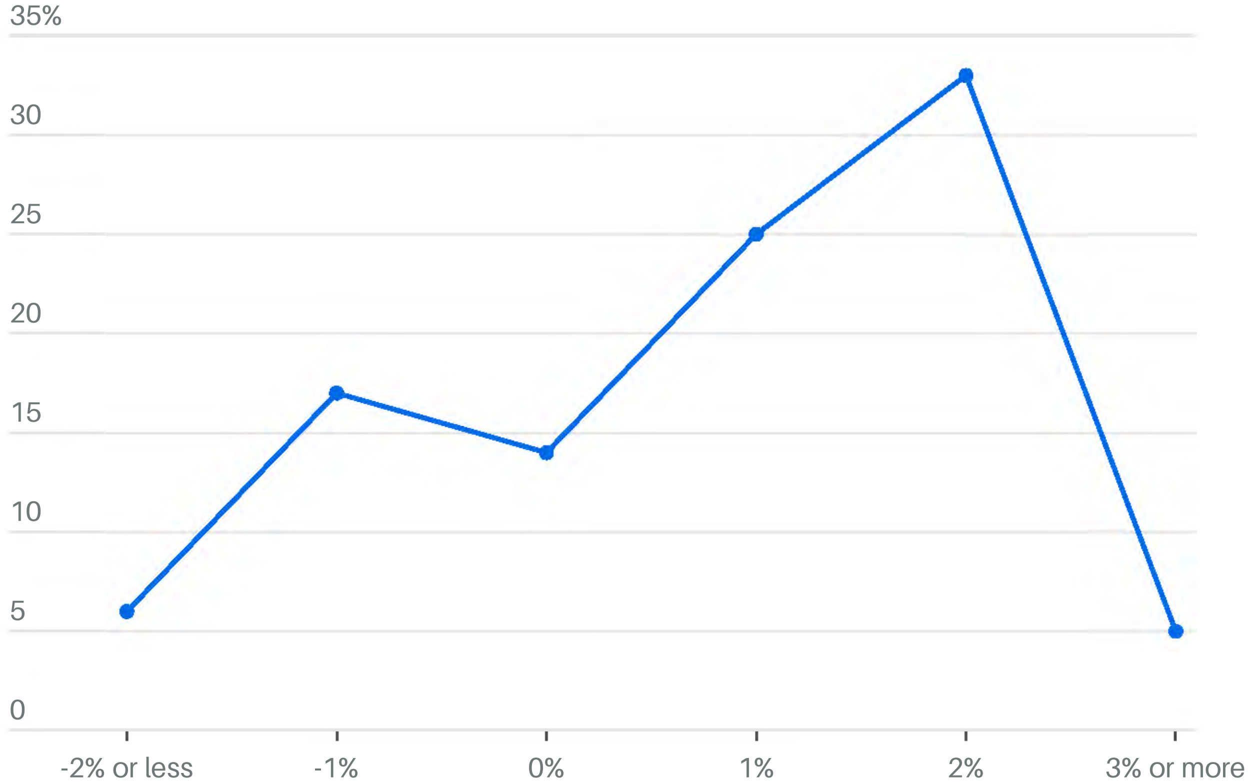
Investment	Price
Oil / WTI (per barrel)	$91
Gold (per troy ounce)	$1,960
Bitcoin	$24,682

The Economy

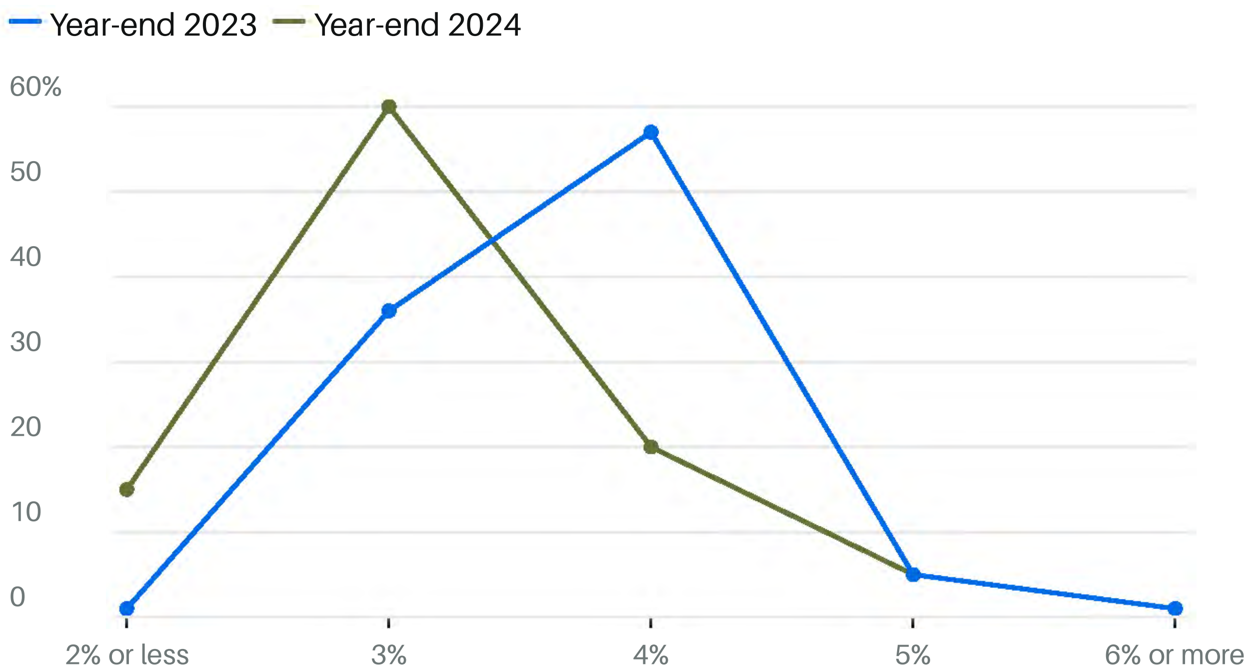
Which best describes your outlook for the U.S. economy in the next 12 months?



Predict the growth rate of real U.S. GDP in 2024.



Predict the year-over-year U.S. inflation rate (consumer price index) at the end of 2023 and 2024.



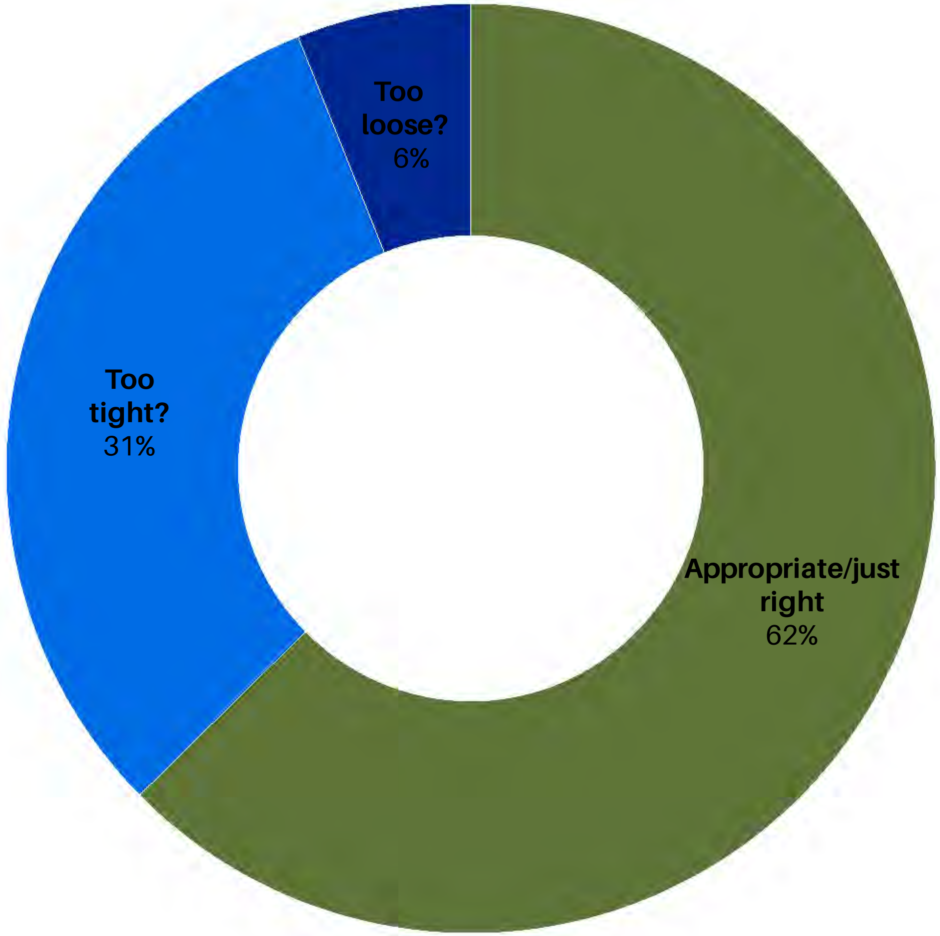
Where will the federal-funds rate be at the end of 2023 and the end of 2024?

Federal-funds rate target range

	2023*	2024
Below 4.25%	0%	8%
4.25%-4.50%	2%	10%
4.50%-4.75%	2%	16%
4.75%-5.00%	5%	28%
5.00%-5.25%	17%	21%
5.25%-5.50%	47%	8%
5.50%-5.75%	26%	8%
5.75%-6.00%	2%	1%

*Percentage doesn't total 100 due to rounding.

Is the Federal Reserve's policy stance...

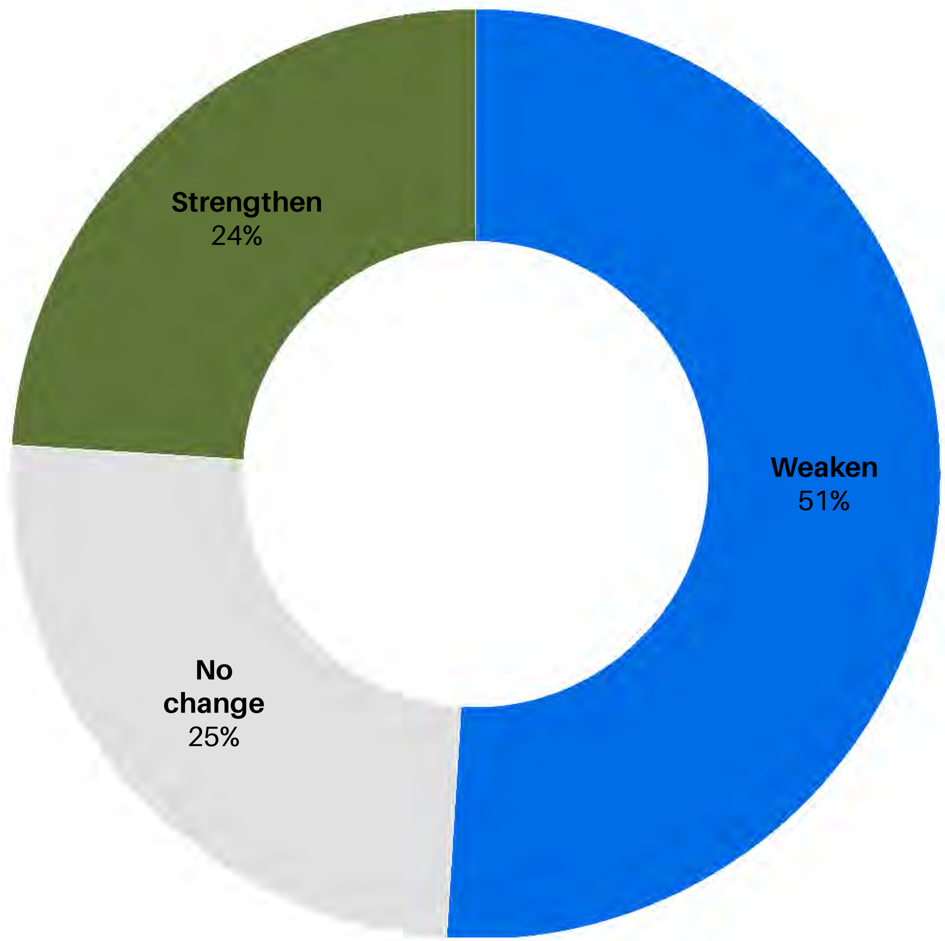


Percentage doesn't total 100 due to rounding.

What will the two-year Treasury note and the 10-year Treasury note yield a year from now?

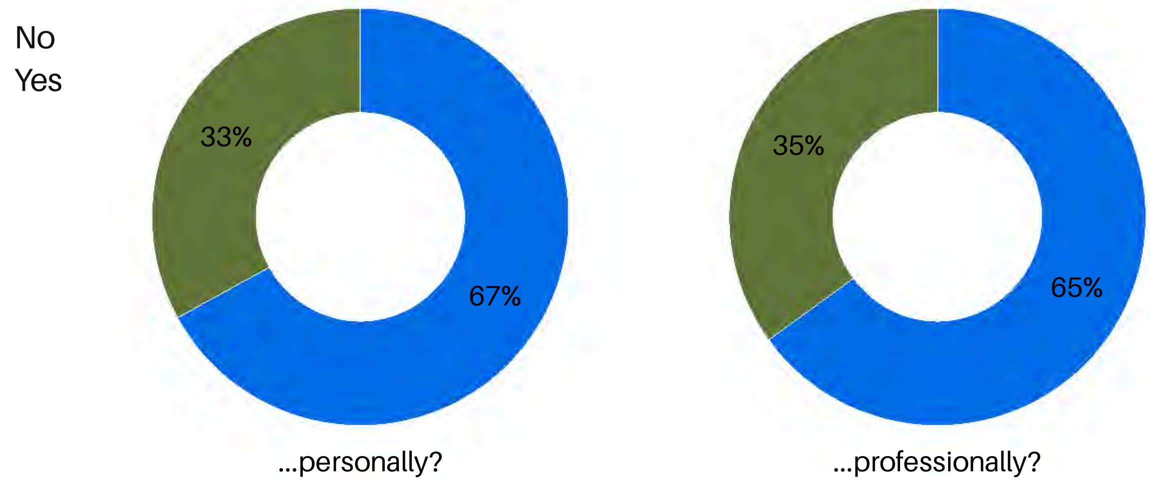
	Two-Year	10-Year
3.00% or less	1%	1%
3.25%	6%	0%
3.50%	4%	6%
3.75%	9%	4%
4.00%	15%	14%
4.25%	13%	10%
4.50%	20%	26%
4.75%	14%	14%
5.00%	13%	14%
5.25%	4%	6%

Will the U.S. Dollar Index (DXY) strengthen, weaken, or stay the same in the next 12 months?



Report Card

Are you beating on the S&P 500 this year...



NDR
NED DAVIS RESEARCH

NDR Sector Views

JANUARY 4, 2024

Risk-on leadership closes out 2023

The S&P 500 rose 4.4%, with all sectors except Energy registering gains in December. Leadership was **cyclical over defensive**, and several oversold Value sectors, including Real Estate, Industrials, and Financials, bounced back to close out the year. Utilities, Consumer Staples, and Health Care all underperformed in December, capping off a dismal 2023 campaign for the defensive sectors.

Historically bad

Consumer Staples and Utilities trailed the S&P 500 in 2023 by their second-widest margins on record for a calendar year since 1973. For Health Care, it was the fifth-worst year. As a group, our defensive SHUT Index has rarely been more oversold.

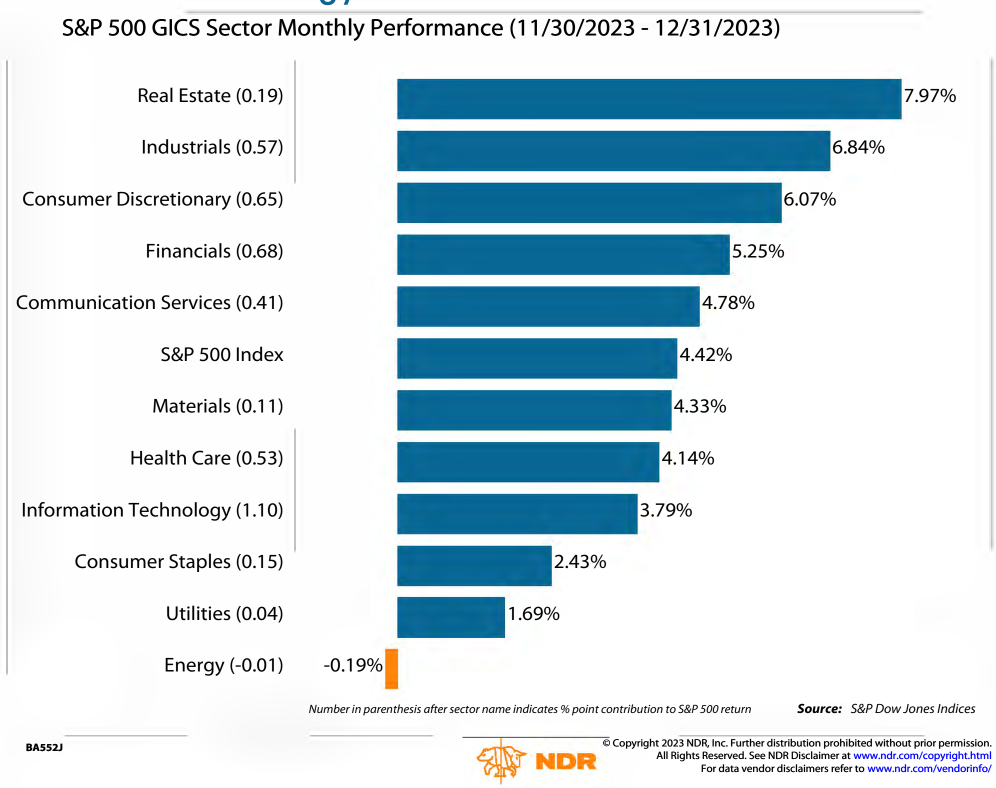
But better times could be ahead. We noted on November 30 that defensive sectors have tended to bounce back in the year following severe underperformances. The defensive group has also outperformed in the months after tightening cycles, in the runup to presidential elections, and after major interest rate peaks, on average.

CURRENT RECOMMENDATIONS

Sector	Position	Recommended	Benchmark
Communication Services	Overweight	12%	8.7%
Industrials	Overweight	12%	8.4%
Consumer Discretionary	Marketweight	10%	10.9%
Energy	Marketweight	4%	4.4%
Financials	Marketweight	12%	12.1%
Materials	Marketweight	2%	2.5%
Real Estate	Marketweight	3%	2.4%
Technology	Marketweight	27%	27.4%
Utilities	Marketweight	3%	2.5%
Consumer Staples	Underweight	3%	7.3%
Health Care	Underweight	12%	13.4%

● Overweight ● Marketweight ● Underweight

All sectors but Energy rose in December



Growth stretched

Despite Growth momentum slowing amid broadening participation since the October 27 S&P 500 low, Technology, Communication Services, and Consumer Discretionary finished 2023 with returns head and shoulders above all other sectors. The tech mega-caps were most responsible for Growth's dominance and **begin the new year with high expectations**.

The nine Tech Titans now make up 28.3% of S&P 500 market cap but only 19.3% of the index's earnings, near its widest gap on record. At the same time, Nasdaq sentiment begins the year at **extreme levels of optimism**.

Model update

The sector model made three position changes at its December month-end

Completely Revised and Updated

VALUATION

MEASURING AND MANAGING THE VALUE OF COMPANIES

THIRD EDITION

UNIVERSITY EDITION

McKinsey & Company, Inc.
Tom Copeland • Tim Koller • Jack Murrin

$$k_p = \frac{\text{div}}{P}$$

where k_p = The cost of preferred stock
div = The promised dividend on the preferred stock
P = The market price of the preferred stock

If the current market price is not available, use yields on similar-quality issues as an estimate. For a fixed-life or callable preferred stock issue, estimate the opportunity cost by using the same approach as for a comparable debt instrument. In other words, estimate the yield that equates the expected stream of payments with the market value. For convertible preferred issues, option-pricing approaches are necessary.

STEP 3: ESTIMATE THE COST OF EQUITY FINANCING

The opportunity cost of equity financing is the most difficult to estimate because we can't directly observe it in the market. We recommend using the capital asset pricing model (CAPM) or the arbitrage pricing model (APM). Both approaches have problems associated with their application, including measurement difficulty. Many other approaches to estimating the cost of equity are conceptually flawed. The dividend yield model (defined as the dividend per share divided by the stock price) and the earnings-to-price ratio model substantially understate the cost of equity by ignoring expected growth.

The Capital Asset Pricing Model

The CAPM is discussed at length in all modern finance texts (for example, see Brealey and Myers, 1999, or Copeland and Weston, 1992).[6] These detailed discussions will not be reproduced here. (In this section, we assume that you are generally familiar with the principles that underlie the approach.) The CAPM postulates that the opportunity cost of equity is equal to the return on risk-free securities plus the company's systematic risk (beta) multiplied by the market price of risk (market risk premium). The equation for the cost of equity (k_s) is as follows:

[6] T. Copeland and J. Weston, *Financial Theory and Corporate Policy*, 3rd ed. (Reading, MA: Addison-Wesley, 1992); and R. Brealey and S. Myers, *Principles of Corporate Finance*, 5th ed. (New York: McGraw-Hill, 1999).

by interest payments; preferred stockholders are compensated by fixed dividend payments; and the firm's remaining income belongs to its common stockholders and serves to "pay the rent" on stockholders' capital. Management may either pay out earnings in the form of dividends or retain earnings for reinvestment in the business. If part of the earnings is retained, an *opportunity cost* is incurred: Stockholders could have received those earnings as dividends and then invested that money in stocks, bonds, real estate, and so on. *Thus, the firm should earn on its retained earnings at least as much as its stockholders themselves could earn on alternative investments of equivalent risk.*

What rate of return can stockholders expect to earn on other investments of equivalent risk? The answer is k_s, because they can earn that return simply by buying the stock of the firm in question or that of a similar firm. Therefore, if our firm cannot invest retained earnings and earn at least k_s, then it should pay those earnings to its stockholders so that they can invest the money themselves in assets that do provide a return of k_s.

Whereas debt and preferred stocks are contractual obligations which have easily determined costs, it is not at all easy to estimate k_s. However, three methods can be used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-premium approach. These methods should not be regarded as mutually exclusive—no one dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods and then choose among them on the basis of our confidence in the data used for each in the specific case at hand.

SELF-TEST QUESTIONS

What are the two types of common equity whose costs must be estimated?

Explain why there is a cost for retained earnings.

THE CAPM APPROACH

As we saw in Chapter 5, the Capital Asset Pricing Model is based on some unrealistic assumptions, and it cannot be empirically verified. Still, because of its logical appeal, the CAPM is often used in the cost of capital estimation process.

Under the CAPM we assume that the cost of equity is equal to the risk-free rate plus a risk premium that is based on the stock's beta coefficient and the market risk premium as set forth in the Security Market Line (SML) equation:

$$\begin{aligned} k_s &= \text{Risk-free rate} + \text{Risk premium} \\ &= \quad k_{RF} \quad + (k_M - k_{RF})b_i. \end{aligned}$$

Given estimates of (1) the risk-free rate, k_{RF}, (2) the firm's beta, b_i, and (3) the required rate of return on the market, k_M, we can estimate the required rate of return of return on the firm's stock, k_s. This required return can then be used as an estimate of the cost of retained earnings.

Estimating the Risk-Free Rate

The starting point for the CAPM cost of equity estimate is k_{RF}, the risk-free rate. There is really no such thing as a truly riskless asset in the U.S. economy. Treasury securities are free of default risk, but long-term T-bonds will suffer capital losses if interest rates rise, and a portfolio invested in short-term T-bills will provide a volatile earnings stream because the rate paid on T-bills varies over time.

Since we cannot in practice find a truly riskless rate upon which to base the CAPM, what rate should we use? Our preference—and this preference is shared by most practitioners—is to use the rate on long-term Treasury bonds. Here are our reasons:

1. Capital market rates include a real, riskless rate (generally thought to vary from 2 to 4 percent) plus a premium for inflation which reflects the expected inflation rate over the life of the security, be it 30 days or 30 years. The expected rate of inflation is likely to be relatively high during booms and low during recessions. Therefore, during booms T-bill rates tend to be high to reflect the high current inflation rate, whereas in recessions T-bill rates are generally low. T-bond rates, on the other hand, reflect expected inflation rates over a long period, so they are far less volatile than T-bill rates.

2. Common stocks are long-term securities, and although a particular stockholder may not have a long investment horizon, most stockholders do invest on a long-term basis. Therefore, it is reasonable to think that stock returns embody long-term inflation expectations similar to those embodied in bonds rather than the short-term expectations in bills. Therefore, the cost of equity should be more highly correlated with T-bond rates than with T-bill rates.

3. Treasury bill rates are subject to more random disturbances than are Treasury bond rates. For example, bills are used by the Federal Reserve System to control the money supply, and bills are also used by foreign governments, firms, and individuals as a temporary safe haven for money. Thus, if the Fed decides to stimulate the economy, it drives down the bill rate, and the same thing happens if trouble erupts somewhere in the world and money flows into U.S. dollars seeking safety. T-bond rates are also influenced by Fed actions and by international money flows, but not to the same extent as T-bill rates. This is another reason why T-bill rates are more volatile than T-bond rates and, most experts agree, more volatile than k_s.

4. T-bills are essentially free of price risk, but they are exposed to a relatively high degree of reinvestment rate risk. Long-term investors such as pension funds and life insurance companies are as concerned about reinvestment rate risk as price risk. Therefore, most long-term investors would feel equally exposed to risk if they held bills or bonds.

5. When the CAPM is used to estimate a particular firm's cost of equity over time, bond rates produce more reasonable results. When T-bill rates were low in 1977

PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17120

Public Meeting held May 12, 2022

Commissioners Present:

Gladys Brown Dutrieuille, Chairman, Statement
John F. Coleman, Jr., Vice Chairman
Ralph V. Yanora

Pennsylvania Public Utility Commission	R-2021-3027385
Bureau of Investigation and Enforcement	
Office of Consumer Advocate	C-2021-3028466
Office of Small Business Advocate	C-2021-3028509
Martha Bronson	C-2021-3028132
Neil Kugelman	C-2021-3028139
Geoffrey Rhine	C-2021-3028170
Theodore Voltolina	C-2021-3028194
Aaron Brown	C-2021-3028279
Darren Distasio	C-2021-3028285
Deena Denesowicz	C-2021-3028288
Vivian George	C-2021-3028310
Nick Panaccio	C-2021-3028331
Richard Regnier	C-2021-3028332
Gerald DiNunzio Jr.	C-2021-3028362
Nancy Reedman	C-2021-3028405
Michael McCall	C-2021-3028413
Raymond Cavalieri	C-2021-3028448
Byron Goldstein	C-2021-3028463
John Grassie	C-2021-3028663
Kyle Brophy	C-2021-3028712
Daniel Savino	C-2021-3028758
Michael Roberts	C-2021-3028869
Treasure Lake Property Owners Association Inc.	C-2021-3029004
Gerardo Giannattasio	C-2021-3029066
Aqua Large Users Group	C-2021-3029089

Erik McElwain	C-2021-3029135
Judy Burton	C-2021-3029152
Brian Edwards	C-2021-3029159
Richard Gage	C-2021-3029393
Joanne Smyth	C-2021-3029411
Jane O'Donovan	C-2021-3029532

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Pennsylvania Public Utility Commission Bureau of Investigation and Enforcement	R-2021-3027386
Office of Consumer Advocate	C-2021-3028467
Office of Small Business Advocate	C-2021-3028511
Camp Stead Property Owners Association	C-2021-3028928
Dale Markowitz	C-2021-3028280
Keith Anthony	C-2021-3028444
Stephanie Boris	C-2021-3028443
Jennifer Buckley	C-2021-3028160
Carl Martinson	C-2021-3028312
Elizabeth O'Neill	C-2021-3028333
Erik and Ilisha Smith	C-2021-3028334
Curtis and Michele Tabor	C-2021-3028335
Gregory Valerio	C-2021-3028336
Jerome Perch	C-2021-3028356
Michael Brull	C-2021-3028361
James Blessing	C-2021-3028402
Elizabeth Yost	C-2021-3028407
Timothy Nicholl	C-2021-3028471
Alyssa Reinhart	C-2021-3028493
James Kolb	C-2021-3028497
Ronald Schneck	C-2021-3028547
Matthew Cicalese	C-2021-3028566
Ronald and Lora	C-2021-3028568
Kelly Frich	C-2021-3028665
Adam Anders	C-2021-3028670
Charleen Falsone	C-2021-3028760
Stephen Grugeon	C-2021-3028892

Lynne Germscheid	C-2021-3028860
Deborah and James Popson	C-2021-3028868
Masthope Mountain Community Association	C-2021-3028996
Treasure Lake Property Owners Association Inc.	C-2021-3029006
East Norriton Township	C-2021-3029019
Kevin Amerman	C-2021-3029063
James Wharton Jr.	C-2021-3029065
Peter and Kim Ginopolas	C-2021-3029096
Yefim Shnayder	C-2021-3029134
Andrea and Matthew Rivera	C-2021-3029154
Judy Burton	C-2021-3029139
Brian Edwards	C-2021-3029161
Edward Coccia	C-2021-3028870
John Day	C-2021-3028734
Robert Dolan	C-2021-3028798
Anthony Giovannone	C-2021-3028794
	C-2021-3028803
	C-2021-3028802
Sheila Gutzait	C-2021-3028634
Rudolph Hofbauer	C-2021-3028666
Ronald and Alexis Koenig	C-2021-3028483
Joan Lipski	C-2021-3028475
William and Ana Loftus	C-2021-3028617
Stephen and Teresa Mason	C-2021-3028576
David Monroe	C-2021-3028567
Lisa Rampone	C-2021-3028804
Lorraine Rocci	C-2021-3028499
David Ross	C-2021-3028479
Carolyn Sica	C-2021-3028446
Dean Swink	C-2021-3028604
Francine Weiner	C-2021-3028639
Tom Woodward	C-2021-3028927
Joseph Torello	C-2021-3029180
Donald Osinski	C-2021-3029413
Lake Associates LLC	C-2021-3029425
	C-2021-3029422
	C-2021-3029419
29 Estates LLC	C-2021-3029417

David Bowers	C-2021-3029466
Joanne Smyth	C-2021-3029411

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BY THE COMMISSION:

Before the Pennsylvania Public Utility Commission (Commission) for consideration and disposition are the Exceptions of Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc. (collectively, Aqua, or the Company), the Commission's Bureau of Investigation and Enforcement (I&E), the Office of Consumer Advocate (OCA), the Office of Small Business Advocate (OSBA), the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (CAUSE-PA), Aqua Large Users Group (Aqua LUG), and Masthope Mountain Community Association (Masthope), filed on February 28, 2022, and the Exceptions of Mr. Donald C. Osinski (Mr. Osinski), filed on February 21, 2022, to the Recommended Decision (R.D.) of Administrative Law Judge (ALJ) Mary D. Long, issued on February 18, 2022, in the above-captioned proceeding. Aqua, I&E, the OCA, the OSBA, and CAUSE-PA filed Replies to Exceptions on March 7, 2022.[1]

For the reasons discussed below, we shall: (1) grant, in part, and deny, in part, the Exceptions filed by Aqua, I&E, and the OCA; and (2) deny the Exceptions filed by the OSBA, CAUSE-PA, Aqua LUG, Masthope, and Mr. Osinski.

Additionally, as discussed below, Aqua proposed rate changes that would have increased its total annual operating revenues for its water service by approximately $86,118,612, or approximately 16.9%, and its total operating revenues for its wastewater service by approximately $11,566,212, or approximately 31.2%, based on a fully projected future test year (FPFTY) ending March 31, 2023.[2] In this Opinion and Order, we shall approve an annual revenue increase of $50,510,192 to the Company's *pro forma*

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[1] Aqua LUG and Masthope each submitted a letter on March 7, 2022 indicating that they would not be filing Replies to Exceptions.

[2] As noted below, Appendix F of Aqua's Main Brief indicates an actual proposed revenue increase of $85,489,328 for its water service and $11,500,997 for its wastewater service.

revenue at present rates of $510,006,687, or approximately 9.88%, for its water service and an annual revenue increase of $18,740,978 to the Company's *pro forma* revenue at present rates of $37,076,494, or approximately 50.55%, for its wastewater service.

I. Background

Aqua provides water and wastewater public utility service to approximately 450,000 water customers and 40,000 wastewater customers in a certificated service territory that spans thirty-two counties across the Commonwealth of Pennsylvania. Aqua is a subsidiary of Essential Utilities, Inc. (Essential Utilities). Aqua last filed for an increase in water and wastewater base rates in 2018, which the Commission addressed at *Pa. PUC, et. al v. Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc.*, Docket Nos. R-2018-3003558 and R-2018-3003561, *et al*. (Order entered May 9, 2019) (*Aqua 2018 Rate Case*).

The Company made its current combined water and wastewater rate increase filing in accordance with the provisions of Section 1311(c) of the Pennsylvania Public Utility Code (Code), 66 Pa. C.S. § 1311(c).[3] Aqua's requested increase was based

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[3] Aqua submitted separate revenue requirement studies for its water and wastewater operations. Further, the Company provided separate wastewater revenue requirement studies for its individual wastewater systems. This included a revenue requirement study for the individual wastewater systems that were presented in the *2018 Aqua Rate Case,* which it referred to as "Wastewater Base," and separate studies for each of the wastewater systems acquired since the *2018 Aqua Rate Case* as part of the Section 1329 Fair Market Value (FMV) acquisition process authorized under 66 Pa. C.S. § 1329. Aqua M.B. at 2. Therefore, the rate tables set forth in the Commission Tables Calculating Allowed Revenue Increase that are attached to this Opinion and Order contain separate sets of rate tables for Aqua's Water Division, as well as separate rate tables for each of the following wastewater systems: Wastewater Base, Wastewater Limerick, Wastewater East Bradford, Wastewater Cheltenham, Wastewater East Norriton, and Wastewater New Garden. Additionally, we have included Table Act 11 – Water and Wastewater Revenue Requirement – Summary and Table RevSum – Water and Wastewater Revenue Requirement – Summary.

upon the FPFTY ending March 31, 2023.[4] The Company sought an increase in water revenues of approximately $85,489,328, or 16.76% of its total Pennsylvania jurisdictional water operating revenues, and an increase in wastewater revenues of approximately $11,500,997, or 31.02% of its total Pennsylvania jurisdictional wastewater operating revenues. These proposed increases reflected the allocation of a portion of the Company's wastewater revenue requirement to its water operations.[5] Aqua M.B. at 1, Appendix F, Water and Wastewater Revenue Requirement - Summary.

Aqua stated that its principal reason for filing its rate increase request is the Company's continuing need to invest in utility infrastructure replacement. Aqua represented that since March 31, 2020, which was the end of the FPFTY used in the *Aqua 2018 Rate Case*, the Company has invested nearly $330 million in utility infrastructure for its water and wastewater operations through the HTY ended March 31, 2021, which is the HTY the Company utilized in this current rate case. Aqua stated that it projects to invest another $800 million through March 31, 2023, including making a meaningful investment in a new financial reporting system, SAP, which will replace the Company's legacy financial reporting system that has been in use for nearly twenty-five years. Aqua noted that increases to its operating and maintenance (O&M) expenses are also a contributing factor in making its rate case filing. Aqua M.B. at 1-2.

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[4] The future test year (FTY) ended March 31, 2022, and the historical test year (HTY) ended March 31, 2021. Aqua M.B. at 15.

[5] In its Main Brief, Aqua stated that it sought an increase in water revenues of approximately $86.118 million and an increase in wastewater revenues of approximately $11.566 million. Aqua M.B. at 1. However, Appendix F, Water and Wastewater Revenue Requirement – Summary shows a final proposed water revenue increase of $85,489,328 and a final proposed wastewater increase of $11,500,997.

II. History of the Proceeding

On August 20, 2021, Aqua filed proposed Tariff Water-Pa P.U.C. No. 3 (Tariff Water No. 3) to become effective October 19, 2021. Under Tariff Water No. 3, the Company proposed to increase Aqua's total annual operating revenues for its water service by approximately $86,118,612, or 16.9%. Also on August 20, 2021, Aqua filed proposed Tariff Sewer-Pa P.U.C. No. 3 (Tariff Sewer No. 3) to become effective October 19, 2021. Under Tariff Sewer No. 3, the Company proposed to increase Aqua's total annual operating revenues for its wastewater service by approximately $11,566,212, or 31.2%.

On September 3, 2021, I&E filed a notice of appearance in both the water and wastewater rate filings. On September 8, 2021, the OSBA filed formal complaints at Docket Nos. C-2021-3028509 (water) and C-2021-3028511 (wastewater). On September 13, 2021, the OCA filed formal complaints at Docket Nos. C-2021-3028466 (water) and C-2021-3028467 (wastewater). Additionally, numerous ratepayers filed complaints. The names of these ratepayers and the Docket Numbers of their Complaints appear on the cover page of this Opinion and Order. CAUSE-PA filed a petition to intervene on September 20, 2021. Masthope filed a petition to intervene, and formal complaints on October 5, 2021 at Docket Nos. at C-2021-3028992 (Water) and C-2021-3028996 (Wastewater).

On September 16, 2021, Commissioner Ralph V. Yanora posed ten Directed Questions to be examined by the Parties as part of these proceedings.

By order entered on October 7, 2021, the Commission suspended the rate filings, pursuant to 66 Pa. C.S. § 1308(d), until May 19, 2022, and directed an investigation to determine the lawfulness, justness, and reasonableness of the rates, rules, and regulations contained in the rate filings.

Forty-five customer complaints by individuals and property owner associations were filed opposing the proposed increase for water. Sixty-seven customer complaints were filed opposing the proposed wastewater rate increases. Three individual complainants requested to become a fully participating party of record: John Day (C-2021-3028734 (wastewater)); Francine Weiner (C-2021-3928639 (wastewater)); and Richard Gage (C-2021-3029393 (water)).

On October 15, 2021, ALJ Long conducted a prehearing conference. Counsel for Aqua, I&E, the OCA and the OSBA appeared. Additionally, counsel representing intervenor CAUSE-PA and complainants Aqua LUG (C-2021-3029089), East Norriton Township (C-2021-3029019), and Masthope, appeared and participated.[6]

At the prehearing conference, the petition to intervene of CAUSE-PA was granted without objection. Following a discussion, the Parties agreed to a schedule for the filing of written testimony, public input hearings, and evidentiary hearings which were scheduled to begin on December 20, 2021.

On October 14, 2021, Aqua filed a motion for a protective order. By interim order entered October 22, 2021, the motion was granted.

Six public input hearings were held November 8, 2021 through November 12, 2021. These public input hearings convened by telephone. A total of fifty-eight witnesses testified.

The active Parties engaged in discovery and served written direct, rebuttal, surrebuttal, and rejoinder testimony. The evidentiary hearing convened as scheduled on

[6] The participants at the prehearing conference constitute the active Parties to this proceeding.

December 20, 2021. The Parties notified the ALJ that they had waived cross-examination of witnesses and requested to move their written testimony into the record. These testimony, exhibits, and hearing exhibits were admitted into the record without objection. All testimony was accompanied with written verification by the corresponding witness.

By interim order entered December 20, 2021, the Parties were provided with briefing instructions. As directed, each Party filed a main brief on January 11, 2022. Complainant John Day filed a letter in lieu of a brief on January 10, 2022. Reply briefs were filed on January 21, 2022. On January 20, 2022, Aqua filed a motion for the admission of a late filed exhibit. Aqua Post-Hearing Exhibit No. 1 was admitted by interim order entered January 24, 2022, and the record was closed.

In the Recommended Decision, issued on February 18, 2022, ALJ Long recommended that Aqua's Tariff Water No. 3 and Tariff Sewer No. 3, and the associated proposed revenue increases, be denied because the Company did not meet its burden of proving by a preponderance of the evidence the justness and reasonableness of every element of its requested increase. Instead, the ALJ recommended the approval of an increase in annual water operating revenue in the amount of approximately $15.2 million, or approximately 2.97% over present rates, and an increase in annual wastewater operating revenue in the amount of approximately $16.7 million, or approximately 45% over present rates. The ALJ also recommended that the Commission approve Aqua's universal service plan and universal service rider, proposed in its filings. Additionally, the ALJ made recommendations regarding pressure valve inspections and fire hydrants and recommended that the Commission approve Aqua's proposal for continued deferral of COVID-19 uncollectible expenses. R.D. at 1-2.

As previously noted, Mr. Osinski filed Exceptions to the Recommended Decision on February 21, 2022, and Aqua, I&E, the OCA, the OSBA, CAUSE-PA, Aqua LUG, and Masthope filed Exceptions on February 28, 2022.

On March 7, 2021, Aqua, I&E, the OCA, the OSBA, and CAUSE-PA filed Replies to Exceptions.

III. Public Input Hearings

As noted above, in the History of Proceeding, six public hearings were convened between November 8, 2021 and November 12, 2021 to hear from Aqua's customers regarding its proposed water and wastewater rate increases. Each of the public input hearings were conducted by telephone using a toll-free telephone number and a PIN. A total of 58 witnesses testified. For a summary of the public input hearings, see pages 4 to 15 of the Recommended Decision.

IV. Legal Standards

At issue here is the Company's request for a general base rate increase, which is governed by Section 1308(d) of the Code, 66 Pa. C.S. § 1308(d). Section 1308(d) of the Code provides the procedures for changing base rates, the time limitations for the suspension of the new rates, and the time limitations on the

Commission's actions. 66 Pa. C.S. § 1308(d).[7] "Under traditional ratemaking, utilities may not change rates charged to customers outside of a base rate case." *McCloskey v. Pa. PUC*, 127 A.3d 860, 863 n.2 (Pa. Cmwlth. 2015).

Section 1301(a) of the Code mandates that "[e]very rate made, demanded, or received by any public utility . . . shall be just and reasonable, and in conformity with [the] regulations or orders of the [C]ommission." 66 Pa. C.S. § 1301(a). Pursuant to the just and reasonable standard, a utility may obtain "a rate that allows it to recover those expenses that are reasonably necessary to provide service to its customers[,] as well as a reasonable rate of return on its investment." *City of Lancaster Sewer Fund v. Pa. PUC*, 793 A.2d 978, 982 (Pa. Cmwlth. 2002) (*City of Lancaster*). There is no single way to arrive at just and reasonable rates, and "[t]he [Commission] has broad discretion in determining whether rates are reasonable" and "is vested with discretion to decide what factors it will consider in setting or evaluating a utility's rates." *Popowsky v. Pa. PUC*, 683 A.2d 958, 961 (Pa. Cmwlth. 1996) (*Popowsky II*).

A public utility is entitled to an opportunity to earn a fair rate of return on the value of the property dedicated to public service. *Pennsylvania Gas and Water Co. v. Pa. PUC*, 341 A.2d 239, 251 (Pa. Cmwlth. 1975) (citations omitted). In determining a fair rate of return, the Commission must adhere to the constitutional standards established by the United States Supreme Court in the seminal cases *Bluefield Water Works and Improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679,

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[7] Among other things, Section 1308(d) of the Code requires the Commission to render a final decision granting or denying, in whole or in part, the general rate increase requested by a public utility, within a general time frame not to exceed seven months from the proposed effective date of the utility's proposed tariff supplement. *See* 66 Pa. C.S. § 1308(d); *see also* 52 Pa. Code § 53.31 (requiring a tariff proposing a rate increase to be effective upon sixty days' advance notice). Unless the utility voluntarily extends the suspension period, the Commission's non-action within this timeframe means, by operation of law, the utility's proposed general rate increase will go into effect, as proposed, at the end of such period. *See* 66 Pa. C.S. § 1308(d).

692-93 (1923) (*Bluefield*) and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) (*Hope Natural Gas*). In *Bluefield*, the Supreme Court stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

Bluefield, 262 U.S. at 692-93. Twenty years later, in *Hope Natural Gas*, the Supreme Court reiterated:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Hope Natural Gas, 320 U.S. at 603.

The Commission is required to investigate all general rate increase filings. *Popowsky II*, 683 A.2d at 961. The burden of proof to establish the justness and reasonableness of every element of a public utility's rate increase request rests solely upon the public utility in all proceedings filed under Section 1308(d) of the Code. 66 Pa. C.S. § 315(a); s*ee also, Lower Frederick Twp. Water Co. v. Pa. PUC*, 409 A.2d 505, 507 (Pa. Cmwlth. 1980) (*Lower Frederick*); *see also*, *Brockway Glass Co. v. Pa. PUC*, 437 A.2d 1067 (Pa. Cmwlth. 1981). Section 315(a) of the Code provides as follows:

> **Reasonableness of rates.** – In any proceeding upon the motion of the commission, involving any proposed or existing rate of any public utility, or in any proceedings upon complaint involving any proposed increase in rates, the burden of proof to show that the rate involved is just and reasonable shall be upon the public utility.

66 Pa. C.S. § 315(a). The evidence necessary to meet that burden must be substantial. *Lower Frederick* at 507.

In general rate increase proceedings, the burden of proof does not shift to parties challenging a requested rate increase. Rather, the utility's burden of establishing the justness and reasonableness of every component of its rate request is an affirmative one, and that burden remains with the public utility throughout the course of the rate proceeding. There is no similar burden placed on parties to justify a proposed adjustment to the Company's filing. The Pennsylvania Supreme Court has held:

> [T]he appellants did not have the burden of proving that the plant additions were improper, unnecessary or too costly; on the contrary, that burden is, by statute, on the utility to demonstrate the reasonable necessity and cost of the installations, and that is the burden which the utility patently failed to carry.

Berner v. Pa. PUC, 116 A.2d 738, 744 (Pa. 1955).

However, in proving that its proposed rates are just and reasonable, a public utility need not affirmatively defend every claim it has made in its filing, even those which no other party has questioned. As the Pennsylvania Commonwealth Court has held:

> While it is axiomatic that a utility has the burden of proving the justness and reasonableness of its proposed rates, it cannot be called upon to account for every action absent prior notice that such action is to be challenged.

Allegheny Center Assocs. v. Pa. PUC, 570 A.2d 149, 153 (Pa. Cmwlth. 1990) (citation omitted); *see also Pa. PUC v. Equitable Gas Co.*, 73 Pa. P.U.C. 301, 359-360 (1990).

Additionally, Section 315(a) of the Code cannot reasonably be read to place the burden of proof on the utility with respect to an issue the utility did not include in its general rate case filing and which, frequently, the utility would oppose. 66 Pa. C.S. § 315(a). The burden of proof must be on the party who proposes a rate increase beyond that sought by the utility. *Pa. PUC v. Metropolitan Edison Company*, Docket No. R-00061366, 2007 Pa. PUC LEXIS 5 (Order entered January 11, 2007). The mere rejection of evidence contrary to that presented by the public utility is not an impermissible shifting of the evidentiary burden. *United States Steel Corp. v. Pa. PUC*, 456 A.2d 686 (Pa. Cmwlth. 1983).

In her Recommended Decision, ALJ Long made 117 Findings of Fact and reached 13 Conclusions of Law. R.D. at 15-30, 137-39. The Findings of Fact and Conclusions of Law are incorporated herein by reference and are adopted without comment unless they are either expressly or by necessary implication rejected or modified by this Opinion and Order.

Finally, any issue or Exception that we do not specifically address shall be deemed to have been duly considered and denied without further discussion. The Commission is not required to consider expressly or at length each contention or argument raised by the parties. *Consolidated Rail Corp. v. Pa. PUC*, 625 A.2d 741 (Pa. Cmwlth. 1993); *also see, generally, University of Pennsylvania v. Pa. PUC*, 485 A.2d 1217 (Pa. Cmwlth. 1984).

V. Impact of the Pandemic

A. Positions of the Parties

The OCA urged the Commission to consider the economic repercussions of the COVID-19 pandemic and the hardships this ongoing reality continues to create for Aqua's ratepayers. In support, the OCA presented statistics on the effects of the pandemic in Pennsylvania and asserted that the Commission should consider these impacts when determining what constitutes a just and reasonable rate for the Company's customers. OCA M.B. at 5-15.

The OCA cited, in part, to job loss data and evidence specific to Pennsylvania residents showing that the lower the household's income the greater the impact the pandemic has on income loss. In addition, the OCA cited to data at the time of briefing showing a significant increase in active COVID-19 cases and deaths in Pennsylvania and rising unemployment rates in Aqua's service territory. The OCA also alleged that the Company charged significant levels of late fee payments during the pandemic, and during the moratorium on terminations. Thus, the OCA requested that the Commission take these factors into consideration when determining the appropriate return on equity (ROE) and the OCA's other recommendations related to the pandemic to keep the rate increase to the lowest possible cost for Aqua's customers. OCA R.B. at 3-4.

Aqua alleged that the OCA has taken an extreme position on a variety of issues, including rate of return, to propose that the Company be ordered to decrease its rates. According to the Company, rejecting any increase, in the face of overwhelming evidence that a rate increase is justified under traditional ratemaking principles, is not a balancing of customers' and investors' interests. Aqua argued that the OCA is attempting to establish a new ratemaking standard that rate increases can be granted or denied based upon subjective assessments of whether a sufficient number of customers will have trouble paying increased rates. The Company submitted that such a standard imperils the execution of needed safety investments in the short term and does long-term harm as investors assess whether to continue to invest in Pennsylvania utilities or shift investment to other states or other enterprises. Aqua R.B. at 2-3 (citing *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket Nos. R-2020-3018835, *et al.* (Order entered February 19, 2021) (*Columbia Gas*)).

The Company also cited to a drop in the unemployment rate since the *Columbia Gas* decision and a fall in the number of Aqua's customer accounts at risk for termination falling below pre-pandemic levels. Aqua asserted that it understands the difficulties faced by customers with an inability to pay. According to the Company, it implemented programs and practices during 2020 and 2021 to help customers who struggled to pay their bills and will provide further assistance with its new Customer Assistance Program (CAP) going forward. However, Aqua argued that it will not be able to meet its obligation to provide safe and reliable service, while also providing for the health and safety of its employees, without appropriate rate relief. Aqua R.B. at 3-4.

B. Recommended Decision

In the Recommended Decision, the ALJ indicated that neither she nor the Commissioners are unmindful of the important concerns raised by the OCA and CAUSE-PA regarding the affordability challenges faced by low-income customers. However, the

ALJ explained that the Commission has repeatedly taken the position that the existence of the pandemic does not suspend the consideration of utility rate increases. R.D. at 35 (citing *Columbia Gas* at 47-52).

The ALJ stated that utilities are expected to continue to provide reasonable service and safe and reliable facilities. Here, the ALJ noted that no Party has challenged Aqua's infrastructure improvement spending or the value of its proposal to continue that spending in this proceeding. Rather, the ALJ continued, some Parties have recommended Aqua put into place additional universal service programming and customer service improvements, which require financial investment to implement. Thus, the ALJ reasoned that her recommendations are an attempt to balance the many competing concerns of the ratepayers with the Company's ongoing challenge to consider the affordability of service while also meeting the increasing environmental and infrastructure obligations in pursuit of safe and reliable service. R.D. at 35

C. OCA Exception No. 28 and Replies

In its Exception No. 28, the OCA argues that the ALJ did not adequately account for the impact of the pandemic on Aqua's ratepayers when setting rates in this proceeding. In support, the OCA submits that it provided unrefuted testimony showing that the economic crisis is ongoing and continues to severely impact the lives of Aqua's ratepayers. The OCA also contends that portions of Aqua's service territory in Northumberland and Columbia counties have the highest hospitalization rates for COVID-19 in the United States. OCA Exc. at 39.

Although the OCA acknowledges that the existence of the pandemic should not suspend the consideration of utility rate increases, the OCA argues that the continued impact of the COVID-19 pandemic should be taken into account in the Commission's consideration of the appropriate return on equity and the OCA's other recommendations related to the pandemic. Further, the OCA asserts that the ALJ's reliance on the Parties' lack of opposition to Aqua's infrastructure spending and the Parties' recommendations regarding improvements to universal service programming and customer service, which require financial investment, inappropriately shifts the burden of proof in this proceeding. The OCA argues that it is not required to challenge the Company's infrastructure spending in order to offer recommendations regarding universal service programming or customer service. OCA Exc. at 39-40.

The OCA notes that additional universal service programming and customer service improvements require financial investment to implement but contends that those financial investments are meant to mitigate the impact of unaffordable rates for Aqua's most vulnerable customers. According to the OCA, the costs of these programs would be fully recovered through surcharges or base rates and the OCA's witnesses took these additional costs into account in their analyses as appropriate means of addressing Aqua's proposed rate increase in this proceeding. *Id*. at 40.

In its reply, Aqua argues that the OCA's Exception No. 28 identifies no specific adjustments to be made. Aqua reiterates that the proper, and constitutional, approach to deal with lingering effects of the pandemic is to implement programs that support those with payment difficulties. According to the Company, this focuses the solution on the problem, rather than hampering Aqua's ability to continue to provide safe, exceptional service by denying adequate rate relief that is supported by the evidence and prior rulings. Aqua submits that its comprehensive, new CAP, including arrearage forgiveness, and its Hardship Fund, along with new federal assistance programs for water customers, will provide that support to payment-troubled customers. The Company contends that the OCA's Exception No. 28, to the extent it seeks to encourage the Commission to rule adversely on issues simply to produce a lower result, should be rejected. Aqua R. Exc. at 23.

D. Disposition

Upon review, we consider the OCA's Exception No. 28 to be a global, generalized objection to the overall recommendations set forth in the Recommended Decision. Here, the OCA does not identify any specific adjustments that should be made. Essentially, the OCA contends that the ALJ failed at a conceptual level to consider the impact of the pandemic when setting rates. However, in the context of this Exception, it is unclear what specific measures or calculations the ALJ should have applied to address the financial impact related to COVID-19.

The Parties' arguments pertaining to each particular issue in the rate proceeding are addressed in detail in this Opinion and Order. Our disposition related to each issue and the resulting calculations are more properly addressed within the context of those issues below. Thus, we decline here to apply an undefined and potentially subjective reductive factor to the following determinations and calculations based on the impact of COVID-19. Overall, we find no error in the ALJ's conclusion that she attempted to balance the competing interests of the ratepayers, the affordability of service, and the increasing environmental and infrastructure obligations to provide safe and reliable water and wastewater utility service.

The Commission has repeatedly determined that the existence of the pandemic does not suspend the consideration of rate cases. *See e.g.*, *Pa. PUC v. Philadelphia Gas Works*, Docket No. R-2020-3017206 (Order entered November 19, 2020), *Pa. PUC v. UGI Utilities, Inc. - Gas Division*, Docket No. R-2019-3015162 (Order entered October 8, 2020) (*UGI Gas*), and *Pittsburgh Water and Sewer Authority*, Docket Nos. R-2020-3017951, R-2020-3017970 (Order entered December 3, 2020). Further, in *Columbia Gas*, we explained that under the traditional set of ratemaking norms there is a consideration and weighing of important factors or principles in setting just and reasonable rates, such as quality of service, gradualism, and rate affordability.

> This is true in normal circumstances as well as extraordinary circumstances, such as this pandemic. Indeed, in our opinion, the applicable legal standards that require the Commission to balance between the interests of the utility's customers, investors, and the public interest, require the Commission, by necessary implication, to weigh evidence or unique considerations related to changes in service, market forces, and the economy. Thus, it is our responsibility under the applicable legal and constitutional standards to weigh evidence and unique considerations related to the COVID-19 pandemic in setting just and reasonable rates, and our continued use of traditional ratemaking methodologies permit our consideration of important ratemaking principles, like gradualism and rate affordability, in relation to this pandemic. Moreover, the traditional ratemaking methodologies permit consideration of evidence presented regarding the risks, uncertainties, and impact of the COVID-19 global pandemic in determining various components of a utility's cost of service, or revenue requirement.

Columbia Gas at 48.

We have and will continue to apply traditional ratemaking methodologies which include the consideration of unique circumstances such as the risks, uncertainties, and impact of the COVID-19 pandemic. Thus, to the extent that the OCA is requesting such action by the Commission in this proceeding, we find the Exception to be unnecessary.

As a final matter, we find the OCA's contention that the ALJ improperly shifted the burden of proof by noting the lack of opposition to infrastructure spending and improvements to universal service programming and customer service as lacking merit. The ALJ's statement did not – nor could it – operate to shift the burden of proof with respect to Aqua's burden to establish the justness and reasonableness of every component of its rate request. There is no indication in the Recommended Decision that this burden somehow shifted to the OCA with respect to its proposed adjustments to the universal service or customer assistance programs.

Accordingly, we shall deny OCA Exception No. 28.

VI. Rate Base

Rate base, also known as measure of value, is the depreciated original cost of a utility's investment in plant a utility has in place to serve customers plus other additions and deductions that the Commission determines to be necessary in order to keep the utility operating and providing safe and reliable service to its customers. Rate base is one part of the financial equation used by the Commission to determine the appropriate revenue that a utility is granted in a rate proceeding. I&E M.B. at 17.

Aqua's rate base claim calculation includes depreciated original cost plant in service plus additions of Materials and Supplies (M&S) and Cash Working Capital (CWC) as well as deductions of contributions in aid of construction (CIAC) and customer advances for construction (CAC), deferred income taxes, and Investment Tax Credit as shown on Schedule G-1 on Aqua Exh. 1-A through 1-G. *Id.*

Additionally, the depreciated original cost is determined by subtracting the book reserve, which is the accumulation of all prior annual depreciation expense, and other items such as salvage value, from the original cost of the plant in service that is projected to be used and useful in the public service. The depreciated original cost of the plant in service is determined by taking a "snapshot" look at the depreciated original cost value of used and useful utility plant in service at the end of the FPFTY. I&E M.B. at 17-18.

Further, for a utility plant to be included in rates, the plant must be used and useful in the provision of utility service to the customers. Therefore, by definition, only plant currently providing or capable of providing utility service to customers or plant projected to be completed and in service by the end of the FPFTY is eligible to be reflected in rates. I&E M.B. at 18.

A. Plant in Service

1. Positions of the Parties

No Party to this proceeding challenged the Company's claim for water or wastewater utility plant in service at the end of the FPFTY, except for the challenge regarding the Company's $2,437,305 positive acquisition adjustment associated with the Borough of Phoenixville Water System, which we shall discuss in the next section, below. R.D. at 36; Aqua M.B. at 18.

The Company's claim for both water and wastewater utility plant in service begins with the actual HTY ending balance for each segment of its operations. Aqua St. 2 at 14. As shown in Table 1, below, the HTY ending balance for water was $4,909,729,427 and the HTY ending balance for wastewater was $500,221,311. Aqua M.B. at 16; Aqua St. 2 at 14; see also Aqua Exh. 1-A, Sch. G-2; Aqua Exhs. 1-B through 1-G, Sch. G-2.

The HTY figures for water and wastewater were then increased to reflect FTY and FPFTY plant additions, net of retirements, and utility plant acquisition adjustments (UPAA)[8] associated with certain acquired systems. Aqua M.B. at 16; Aqua St. 2 at 14-15; Aqua St. 2, Attachment 1.

For the FTY for its water operations, the Company projected additions totaling $402,940,579 and retirements totaling ($36,896,955). Aqua St. 2, Attachment 1 at 1. For the FPFTY for its water operations, the Company projected additions totaling $314,771,304 and retirements totaling ($28,466,740). Aqua M.B. at 16-17; Aqua St. 2, Attachment 1 at 2.

For the FTY for its wastewater operations, the Company projected additions totaling $34,134,821 and retirements totaling ($3,416,157). Aqua St. 2, Attachment 2 at 1. For the FPFTY, the Company projected additions totaling $38,897,468 and retirements totaling ($3,014,299). Aqua M.B. at 18; Aqua St. 2, Attachment 2 at 2.

Aqua Proposed Plant In Service						
Operations	HTY	FTY Additions/Retirements		FPFTY Additions/Retirements		FPFTY
	Plant In Service	Additions	Retirements	Additions	Retirements	Plant In Service
Water	$4,909,729,427	$402,940,579	($36,896,955)	$314,771,304	($28,466,740)	$5,562,077,614
Wastewater	$500,221,311	$34,134,821	($3,416,157)	$38,897,468	($3,014,299)	$566,823,145

Table 1: Aqua-Proposed Plant In Service for Water and Wastewater Operations.

Accordingly, the Company's FPFTY claim for its water utility plant in service is $5,562,077,614 (Aqua Exhibit 1-A, Schedule G-2) and the FPFTY claim for its wastewater utility plant in service is $566,823,145. Aqua M.B. at 18; Aqua Exhs. 1-B through 1-G, Sch. G-2.

8 The Company's HTY figures presented on Schedule G-2 do not reflect the Company's proposed UPAA. Adjustments related to proposed UPAA are reflected in Schedule G-3 of Aqua Exhibits 1-A and 1-G through 1-G. All UPAA shown have been previously approved by the Commission, with the exception of the Borough of Phoenixville acquisition. Aqua M.B. at 16, n. 4.

I&E recommended that the Company provide the Commission's Bureaus of Technical Utility Services (TUS) and I&E with an update to Schedule G-2 of Aqua Exhibits 1-A, 1-B, 1-C, 1-D, 1-E, 1-F, and 1-G, no later than July 1, 2022 which should include actual capital expenditures, plant additions, and retirements by month for the twelve months ending March 31, 2022 and an additional update for actuals for the year ending March 31, 2023, no later than July 1, 2023. I&E reasoned that, through the use of an FPFTY, a utility is allowed to require ratepayers, in essence, to pre-pay a return on a utility's projected investment in future facilities that are not in place and providing service at the time the new rates take effect and are not subject to any guarantee of being completed and placed into service. According to I&E, while the FPFTY provides for such projections, there should be some timely verification of the projections. I&E further submitted that the use of a FPFTY has become common practice by Pennsylvania utilities, including Aqua, and the Company agreed to provide such projections as part of its previous base rate case in which it made use of the FPFTY. I&E further noted that the Company did not challenge I&E's recommendation to continue to provide the requested updates. I&E M.B. at 21-22.

2. Recommended Decision

Except for the Company's proposed positive acquisition adjustment of $2,437,305 to its water rate base associated with the Phoenixville System (addressed in Section VI.B, below), the ALJ recommended that the remainder of the Company's proposed adjustments to its water utility plant in service and all of the Company's adjustments to its wastewater utility plant in service at the end of the FPFTY be adopted. R.D. at 36.

The ALJ also recommend that I&E's reporting request be approved. In making this recommendation, the ALJ noted that this is a reporting requirement consistent with Section 315(e) of the Code, 66 Pa. C.S. § 315(e), which requires that when a utility utilizes a FPFTY in any rate proceeding and such FPFTY forms a substantive basis for the Commission's final rate determination, the utility shall provide, as specified by the Commission in its Final Order, appropriate data evidencing the accuracy of the estimates contained in the FPFTY. R.D. at 39.

3. Disposition

Aside from the positive acquisition adjustment proposed by the Company with regard to its Phoenixville Water System (addressed immediately below), no other Party filed Exceptions on the Company's remaining proposed adjustments to its plant in service. Finding the ALJ's recommendation to be reasonable, we adopt it without further comment.

B. Water Rate Base – Borough of Phoenixville

In 2019, the Commission approved Aqua's acquisition of the water system assets of the Borough of Phoenixville, Chester County, PA (Borough) that included all of Phoenixville's water service territories located outside of its municipal borough boundaries (*i.e.*, extraterritorial water system) (hereinafter, Phoenixville Water System).[9] In this proceeding, the primary adjustment to rate base is related to the Company's

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[9] *Joint Application of Aqua Pennsylvania, Inc. and the Borough of Phoenixville for approval of (1) the acquisition by Aqua of the water system assets of Phoenixville used in connection with the water service provided by Phoenixville in East Pikeland and Schuylkill Townships, Chester County, and Upper Providence Township, Montgomery County, PA; (2) the right of Aqua to begin to supply water service to the public in portions of East Pikeland Township, Chester County, and Upper Providence Township, Montgomery County, PA; and (3) the abandonment of Phoenixville of public water service in East Pikeland Township, Chester County, and Upper Providence Township, Montgomery County, and certain locations in Schuylkill Township, Chester County, PA*, Docket Nos. A-2018-2642837, A-2018-2642839, *et al*. (Recommended Decision dated September 13, 2019), adopted as final (Order entered October 24, 2019) (*Aqua-Phoenixville Order*).

proposal to include recovery of the acquisition premium that Aqua paid for the Phoenixville Water System. The depreciated cost of the Phoenixville Water System was $1,026,724, and Aqua paid $2,437,305 more for the assets than the depreciated original cost, creating a total purchase price of $3,464,029. R.D. at 18, FOF No. 20.

The OCA and I&E opposed this recovery, as well as the Company's related amortization expense claim. They argued that because the Company failed to provide sufficient evidence that the Borough was failing to render reasonable and adequate service at the time the Phoenixville Water System was acquired by Aqua pursuant to Section 1327(a) of the Code, the Company should not be permitted to recover the acquisition premium in rate base. R.D. at 43. The ALJ agreed with the OCA and recommended that $2,437,305 be removed from Aqua's rate base, and the concomitant adjustments be made to the accrued depreciation reserve and annual amortization expense. R.D. at 44. The details concerning this issue are more fully discussed immediately below.

1. Positions of the Parties

The Company requested that the Commission permit it to include an acquisition adjustment[10] of $2,437,305 in water rate base (see Aqua Exh. 1-A, Sch. C-5.1, line 3) for the price it paid beyond the depreciated original cost to acquire a portion of the Phoenixville Water System consistent with Section 1327 of the Code, 66 Pa. C.S.

[10] Section 1327 (a) provides that "If a public utility acquires property from another public utility, a municipal corporation or a person at a cost which is in excess of the original cost of the property when first devoted to the public service less the applicable accrued depreciation, it shall be a rebuttable presumption that the excess is reasonable and that excess shall be included in the rate base of the acquiring public utility, provided that the acquiring public utility proves that [it has met the requirements of included in Section 1327(a)(1)-(9)]."

§ 1327(a).[11] The Company further proposed that the acquisition adjustment be amortized over a period of twenty years. Aqua M.B. at 15. Aqua reflected $2,315,440 in the positive acquisition adjustment as of the end of the FPFTY as set forth in Aqua Exh. 1-A, Schedule G-3. *Id.* at 19.

Aqua based its acquisition adjustment claim on the fact that it paid more than the depreciated original cost for the assets, and it is therefore allegedly entitled to include the excess in rate base, because it meets the nine criteria set forth in Section 1327(a) of the Code to show that the Phoenixville Water System was a troubled water system on the date it was acquired. Aqua M.B. at 24-26; Aqua St. 2 at 16.

Aqua explained that the genesis of its purchase of the assets of the Phoenixville Water System that previously served the water customers located outside of the Borough's municipal boundaries was the result of the Borough's 2013 Petition and the Commission's 2015 Order on same. The Borough had requested that the Commission declare that the Phoenixville Water System is not subject to the Commission's jurisdiction so that it could better economize and manage its limited resources by reducing regulatory compliance costs and administrative costs.[12] R.D. at 42; *Phoenixville Petition Order* at 4. In its petition, the Borough explained that it was deterred from seeking rate relief for service to the extraterritorial customers because the cost and manpower required to prepare and defend a rate filing posed a strain on Borough resources. R.D. at 42. As a result, the Borough's territorial customers were subsidizing

[11] R.D. at 39-44; Aqua St. 2 at 16; Aqua Exh. 3-A; Aqua M.B. at 16-19; I&E M.B. at 6-7, 18, 21-22; OCA M.B. at 17; Aqua R.B. at 9-10; I&E M.B. at 6-7, 18, 21-22; Aqua R.B. at 9-10; I&E RB at 3, 16; OCA R.B. at 6.

[12] *Petition of the Borough of Phoenixville for a Declaratory Order that the Provision of Water and Wastewater Service to Isolated Customers in Adjoining Townships Does Not Constitute the Provision of Public Utility Service Under 66 Pa. C.S. § 102*, Docket No. P-2013-2389321 (Order entered May 19, 2015) (*Phoenixville Petition Order*).

service to the Borough's extraterritorial customers. *Id.* In denying the petition, the Commission acknowledged that seeking rate relief could be perceived as "burdensome," but observed that the Borough had the option to seek relief from regulatory burdens by approaching nearby systems owned by Aqua Pennsylvania and Pennsylvania-American Water Company. *Id.*; *Phoenixville Petition Order* at 7-8. Thereafter, the Borough reached an agreement with Aqua for the transfer of the system. As noted, the Joint Petition for Settlement of the acquisition was approved by the Commission in 2019. *Id.*

Aqua argued that the Phoenixville Water System was a troubled water system on the date it was acquired because it was not being maintained to provide adequate, efficient, safe, and reasonable service and facilities to customers outside the Borough limits. This was allegedly due to the following factors: (1) the Borough was manually reading residential and commercial meters; (2) non-revenue (unaccounted for) water was estimated to be 68%; and (3) 30%, or 32 out of the 105 system fire hydrants, needed to be repaired or replaced. Accordingly, Aqua argued, pursuant to Section 1327(a) of the Code, it is entitled to "a rebuttable presumption that the excess [it paid beyond the depreciated original cost] is reasonable, and that excess shall be included in the rate base of the acquiring utility." Aqua M.B. at 22 (citing Aqua St. at 16 and Aqua Exh. 3-A).

Aqua also argued that the high level of 68% for non-revenue or unaccounted-for water is extremely poor and indicates substantial leaks and metering issues. Aqua M.B. at 25. Aqua cited the Commission's Statement of Policy in Section 65.20(4) of the Commission's Regulations, 52 Pa. Code § 65.20(4), on water conservation which notes that unaccounted-for water levels above 20% have been considered by the Commission to be excessive. *Id.* Thus, Aqua opined that the high level of non-revenue or unaccounted-for water, estimated at 68%, is extremely poor and indicates substantial leaks and metering issues and that "[h]aving non-revenue water of approximating 68%, and having to replace 30% of all hydrants in the system is a clear indication that this was a troubled system." Aqua M. B. at 25; Aqua St. 2-R at 8.

The Company also submitted that after it purchased the Phoenixville Water System, it proactively performed leak surveys, verified hydrant pressures, and checked valve operations and then placed the system on its ongoing maintenance program. Aqua M.B. at 28 (citing Aqua St. 2-R at 8-9). According to Aqua, in view of the fact that it investigated significant unaccounted-for water issues and targeted the resolution of these issues via its maintenance program makes clear that the Borough had failed to maintain its fire hydrants and repair leaking water lines during its ownership. *Id.* Aqua contended that "fire protection is a significant safety and reliability issue which the Company addressed by inspecting 105 fire hydrants, replacing 13 hydrants, and repairing 19 hydrants." Aqua M.B. at 28 (citing Aqua St. 2-R at 8). In addition, the Company contended that its meter replacement efforts addressed issues related to meter reading and billing of customers. Aqua M.B. at 29 (citing Aqua St. 2-R at 9). For all of the above reasons, Aqua believed it has adequately satisfied the requirement of Section 1327(a)(3)(v) that the Borough's water system was troubled at the time it was acquired.

Both I&E and the OCA argued that the $2,437,305 acquisition adjustment should not be permitted because the reasons provided by Aqua are not sufficient to satisfy the extensive Section 1327(a)(3) criteria. I&E St. 3-SR at 2-7; I&E M.B. at 18-21; OCA St. 2 at 11; OCA M.B. at 17-21. I&E and the OCA contended that there is no evidence that Aqua's Phoenixville Water System acquisition was necessitated by the inability of the Borough to render reasonable and appropriate service to customers. *Id.* I&E and the OCA argued that Aqua's rate base claim for its water operations should be denied, and the total annual amortization expense claimed by the Company should be reduced to $409,015 ($530,879 - $121,865). R.D. at 39; I&E M.B. at 18-21; I&E St. 3-SR at 3-7; OCA M.B. at 17-21.

Regarding the Company's citation to the Commission's Statement of Policy on water conservation measures in 52 Pa. Code § 65.20 in support of its position that any water provider with unaccounted-for water above 20% is considered a troubled water system, I&E acknowledged that Section 65.20(4) does mention that unaccounted-for water levels should be kept within reasonable amounts, noting that levels above 20% have been considered by the Commission to be excessive. I&E M.B. at 14-15. However, I&E asserted that Section 65.20(4) does not stand for the presumption that a system experiencing above 20% unaccounted-for water is a *de-facto* troubled water system. I&E M.B. at 15. I&E noted there are various other end-of-service plant issues that were known or knowable that could be the cause, and Section 65.20 merely advises that water conservation measures may be necessary. *Id.*

Specifically, I&E argued: (1) hydrants are utility plant that require periodic replacement based on known and knowable service life; (2) Aqua provided no detail to indicate that there were substantial service issues or failed systems causing the 68% non-revenue water; and much of this non-revenue water could be due to other end-of-service plant issues that were known or knowable; (3) the motivation of an owner to sell is not listed in the Section 1327(a) criteria; and (4) small, private water and wastewater systems do not have the ability to increase taxes and issue bonds that a municipality such as the Borough has, so not every troubled system has the capability of funding necessary repairs. I&E M.B. at 19-20.

The OCA agreed with I&E and added that: (1) the Company did not provide any evidence that the Borough was in violation of statutory or regulatory requirements of the Pennsylvania Department of Environmental Protection or the Commission when the Company acquired the Phoenixville Water System assets; (2) in approving the acquisition, the Commission itself made no findings of inadequate financial, managerial, or technical ability of the Borough; (3) the Commission found no deficiencies concerning the availability of water, the palatability of water, or the provision of water at adequate volume and pressure when the assets were owned by the Borough; and (4) the Commission found no issues with the acquired assets that would require necessary improvements to the plant or distribution system. OCA St. 2 at 11-12. In addition, the OCA argued that the acquisition was only for a portion of the Borough's system (*i.e.*, the portion located outside its municipal boundaries), and that the Borough continues to operate a system serving water and wastewater customers, as well as providing wholesale water supply to Aqua, which is evidence that the Borough was not providing inadequate service at the time of the acquisition. OCA St. 2 at 13-14.

With regard to Aqua's argument that the Commission's encouragement for the Company to sell the Phoenixville assets provides further support that the Company has satisfied the requirements of Section 1327, the OCA responded that while this may be true, it is not dispositive of the issue of whether the system was failing. OCA R.B. at 7. The OCA asserted that the Commission encouraged the sale of the Phoenixville assets to Aqua, in part, to resolve the Borough's inability to fund rate cases before the Commission, since as the Borough described, the costs of rate filings are significant and disproportionate to the "minimal revenues recovered from the Borough's small extraterritorial customer base." Aqua M.B. at 20 (citing *Phoenixville Petition Order* at 3-4). However, the OCA noted that the Commission has found that if a system does not have the financial resources to supply service outside of its service territory, or to remedy water quality problems near its territory, this does not indicate that the system was failing to maintain adequate, efficient, safe, and reasonable service and facilities at the time of the acquisition. OCA R.B. at 7 (citing *Pa. PUC v. Citizens Util. Water Co.*, 1996 Pa. P.U.C. LEXIS 167 at *20, *27-28).

2. Recommended Decision

The ALJ agreed with I&E and the OCA that they have successfully rebutted the presumption of the reasonableness of the excess paid for the Phoenixville

Water System. The ALJ found that there is no evidence that the Borough was failing to render reasonable and adequate service to its extraterritorial customers at the time it was acquired by Aqua. In addition, the ALJ explained that the Commission expects Class A public utilities, such as Aqua, to have completed a thorough analysis of the system's condition as part of any acquisition prior to making an offer, reaching an acquisition price, and closing on a transaction. R.D. at 43.

The ALJ further stated that all systems need ongoing maintenance and investment, and Aqua's meter replacement activity and routine maintenance only indicates that the Company is fulfilling its role as the new owner of the system. The ALJ noted that, while it is true that the estimated lost and unaccounted-for water is a concern and should be addressed, there may be a number of factors other than the failure of the facilities which contributed to the unaccounted-for water. However, the ALJ concluded that those factors alone do not support a conclusion that the service rendered by the Borough was inadequate within the meaning of Section 1327. R.D. at 43.

For the above reasons, the ALJ recommended that $2,437,305 be removed from Aqua's rate base, and the concomitant adjustments be made to the accrued depreciation reserve[13] and annual amortization expense which is expressed as a depreciation expense in this filing.[14] R.D. at 44.

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[13] *See* Aqua M.B. at 18.

[14] These adjustments are reflected in the Appendix to the Recommended Decision in Table II - Water, Rows "Acquis. Adj. – Phoenixville" and "Amort. Phoenixville Acquis. Adj."

3. Aqua Exception No. 2 and Replies

In its Exception No. 2, Aqua disagrees with the ALJ's decision to adopt I&E's and the OCA's positions to disallow the proposed acquisition adjustment in rate base and its amortization over a twenty-year period. Aqua Exc. at 15.

First, the Company argues that the Recommended Decision ignores the regulatory requirements imposed by the Commission in its *Phoenixville Petition Order* which prompted the acquisition. R.D. at 16. In this regard, Aqua contends:

> [T]he RD fails to analyze, or even acknowledge, the Commission's prior findings that (a) recognized Phoenixville's inside-the-borough customers were subsidizing the service provided to outside-the-borough customers, and the defense of a base rate filing had deterred it from seeking rate relief to invest in its system, (b) the Commission had previously directed Phoenixville to avail itself of an acquisition to alleviate these burdens, and (c) Aqua PA's acquisition of the system is consistent with the regulatory requirement established in the *Phoenixville Petition Order*.

Aqua Exc. at 16 (footnotes omitted). In addition, the Company notes that the Commission also previously concluded, as a matter of law, that through the *Phoenixville Petition Order*, the Commission "encouraged the Borough to pursue a sale of its water system assets." Aqua Exc. at 16 (citing *Aqua-Phoenixville Order* at 19, Conclusion of Law ¶ 14).

Next, Aqua submits that the ALJ's recommendation is also incorrect that there is no evidence that the Borough was failing to render reasonable and adequate service at the time of the acquisition. Aqua maintains its argument that the Borough was failing to render reasonable and adequate service when it was acquired because the Borough was still manually reading meters, the system experienced 68% of unaccounted-for water, and 30% of the system fire hydrants required repair or replacement. Aqua Exc. at 16.

Aqua asserts that the ALJ attempted to sidestep the above facts by arguing that those conditions are matters that reflect ongoing maintenance and investment requirements and that high levels of unaccounted-for water were not indicative of system failure. Aqua contends that the sidestepping of these issues divorces the existence of the conditions from the reasons the Borough was unable to address them during its ownership. Aqua cites to the following excerpt from the *Phoenixville Petition Order* in support of its argument that the Borough was not able to address the conditions prior to the acquisition:

> In past years, the disproportionate cost of rate filings compared to the minimal revenues recovered from the Borough's small extraterritorial customer base has deterred the Borough from seeking rate relief and created cost subsidies flowing from inside-borough customers to outside-borough customers.

Aqua M.B. at 17 (citing *Phoenixville Petition Order* at 3 (quoting Borough Petition); Aqua M.B. at 29-30).

Aqua also submits that the ALJ's conclusion that the Company completed a thorough analysis of the system prior to making an offer and closing on the acquisition similarly misses the point. Aqua notes that it addressed this very argument, raised by I&E, in its Reply Brief:

> First, the fact that poor conditions are known or knowable at the time of the acquisition is not the test; and if it was, it would completely undermine the purpose of Section 1327. Second, the assertion that the conditions were "known or knowable" actually supports the fact that the system was troubled at the time it was acquired, and that Aqua PA has

> satisfied the requirements of Section 1327(a)(3), which is to encourage acquisition of troubled systems.

Aqua Exc. at 17 (citing Aqua R.B. at 13). Aqua argues that Section 1327 would be a "legal nullity" if the public utility's showing under Section 1327 could be successfully rebutted by the claim that the poor conditions of the system were "known or knowable" at the time of the acquisition, or that the public utility conducted a thorough investigation of the system prior to acquiring it. Aqua contends that this would make it impossible to identify a troubled system for acquisition consistent with Section 1327 and Commission policy, because the identification of the poor conditions that would satisfy Section 1327 would also render it ineligible for the rebuttable presumption established by this section. Aqua Exc. at 17-18.

Lastly, the Company avers that the ALJ ignored the Commission's policy statement in Section 69.711 of its Regulations, 52 Pa. Code § 69.711, which encourages regionalization and the acquisition of smaller troubled systems by larger capable public utilities. Aqua Exc. at 18. Aqua maintains that it presented credible testimony that the Phoenixville Water System was a prime candidate for using this policy and that the acquisition here is consistent with the Commission's policy. *Id*. at 18 (citing Aqua St. 2-R at 8, Aqua M.B. at 30; and Aqua R.B. at 13).

In reply to Aqua's Exceptions, I&E asserts that Aqua's arguments do not accurately reflect the ALJ's recommendation. First, I&E submits that Aqua erroneously argues that the ALJ failed to recognize that the Borough's water customers within the Borough's boundaries were subsidizing the water service provided to the extraterritorial borough customers. I&E R. Exc. at 6 (citing Aqua Exc. at 16). According to I&E, Aqua's argument is irrelevant in that such subsidization is a rate structure concern internal to the Borough. I&E points to the testimony it provided that the Borough (unlike a small private system) had many funding options to alleviate this problem. I&E R. Exc. at 7 (citing I&E St. 3-SR at 6; I&E St. 3 at 7-9).

I&E also asserts that Aqua's decision to pay in excess of the depreciated original cost for the subject assets does not guarantee recovery. I&E R. Exc. at 7. I&E cites the ALJ's observation that the excess Aqua chose to pay for the Phoenixville Water System created a rebuttable presumption and the ALJ determined that the presumption was successfully rebutted by I&E and the OCA. I&E R. Exc. at 7 (citing R.D. at 43). I&E further avers that the Commission's notation in the *Phoenixville Petition Order* that the Borough could explore a possible acquisition does not justify Aqua's decision to pay more than book value. *Id.*

I&E disagrees that the ALJ sidestepped Aqua's argument about the conditions of the Borough's water system prior to its acquisition (*i.e.*, manually reading meters, 68% of unaccounted-for water, and 30% of the system fire hydrants requiring repair or replacement) and, thus, the acquired Phoenixville Water System was non-viable at the time of acquisition. I&E asserts that the ALJ considered the factors raised by Aqua and rebutted by I&E and the OCA and clearly concluded that those factors alone do not support a conclusion that the service rendered by the Borough was inadequate within the meaning of Section 1327. I&E R. Exc. at 7.

I&E also contends that Aqua's regionalization argument is irrelevant to Aqua's choice to pay more than book value for the system and further notes that the regionalization concept also would have applied if Aqua had paid less than book value. I&E R. Exc. at 7. In closing, I&E explains that "the Commission expects Class A public utilities, such as Aqua, to have completed a thorough analysis as part of any acquisition to factor the condition of a system prior to making an offer and closing on a transaction." *Id*. at 7 (citing R.D. at 43).

The OCA's replies on this issue comport generally with those of I&E. OCA R. Exc. at 1. In addition, the OCA submits that the Company incorrectly claimed that the Commission, in its *Phoenixville Petition Order,* "directed" the Borough to consider selling its extraterritorial assets, thereby allegedly indicating that the Borough was not providing adequate service. OCA R. Exc. at 2 (citing Aqua Exc. at 16). The OCA clarifies that the Commission did not "direct" the Borough to consider selling. *Id*. The OCA notes the ALJ's finding that the Commission simply "observed" that the Borough had the "option to seek relief from regulatory burdens" by transferring its systems to an investor-owned utility like Aqua. OCA R. Exc. at 2 (citing R.D. at 42). Because there is no evidence in the record that the Borough was providing inadequate service at the time of the Company's acquisition, the OCA avers that the ALJ properly rejected the Company's proposal for a positive acquisition adjustment for the Phoenixville Water System, along with its associated $121,865 amortization expense, which is expressed as a depreciation expense in this filing. OCA R. Exc. at 2 (citing OCA M.B. at 21; OCA Table II (Water)).

4. Disposition

Aqua based its acquisition adjustment claim on the fact that it paid more than the depreciated original cost for the assets, and it is therefore entitled to include the acquired facilities in rate base because it meets the nine criteria set forth in Section 1327(a) of the Code. Aqua M.B. at 24-26; Aqua St. 2 at 16. For convenience, Section 1327(a) is stated in its entirety below:

> **(a) Acquisition cost greater than depreciated original cost.--**If a public utility acquires property from another public utility, a municipal corporation or a person at a cost which is in excess of the original cost of the property when first devoted to the public service less the applicable accrued depreciation, it shall be a rebuttable presumption that the excess is reasonable and that excess

shall be included in the rate base of the acquiring public utility, provided that the acquiring public utility proves that:

(1) the property is used and useful in providing water or sewer service;

(2) the public utility acquired the property from another public utility, a municipal corporation or a person which had 3,300 or fewer customer connections or which was nonviable in the absence of the acquisition;

(3) the public utility, municipal corporation or person from which the property was acquired was not, at the time of acquisition, furnishing and maintaining adequate, efficient, safe and reasonable service and facilities, evidence of which shall include, but not be limited to, any one or more of the following:

(i) violation of statutory or regulatory requirements of the Department of Environmental Resources [[15]] or the commission concerning the safety, adequacy, efficiency or reasonableness of service and facilities;

(ii) a finding by the commission of inadequate financial, managerial or technical ability of the small water or sewer utility;

(iii) a finding by the commission that there is a present deficiency concerning the availability of water, the palatability of water or the provision of water at adequate volume and pressure;

(iv) a finding by the commission that the small water or sewer utility, because of necessary

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[15] The Department of Environmental Resources, referred to in Section 1327(a)(3)(i), was abolished by Act 18 of 1995. Its functions were transferred to the Department of Conservation and Natural Resources (DCNR) and the Pennsylvania Department of Environmental Protection (PADEP). R.D. at 42, n.24.

> > improvements to its plant or distribution system, cannot reasonably be expected to furnish and maintain adequate service to its customers in the future at rates equal to or less than those of the acquiring public utility; or
> >
> > (v) any other facts, as the commission may determine, that evidence the inability of the small water or sewer utility to furnish or maintain adequate, efficient, safe and reasonable service and facilities;
>
> (4) reasonable and prudent investments will be made to assure that the customers served by the property will receive adequate, efficient, safe and reasonable service;
>
> (5) the public utility, municipal corporation or person whose property is being acquired is in agreement with the acquisition and the negotiations which led to the acquisition were conducted at arm's length;
>
> (6) the actual purchase price is reasonable;
>
> (7) neither the acquiring nor the selling public utility, municipal corporation or person is an affiliated interest of the other;
>
> (8) the rates charged by the acquiring public utility to its preacquisition customers will not increase unreasonably because of the acquisition; and
>
> (9) the excess of the acquisition cost over the depreciated original cost will be added to the rate base to be amortized as an addition to expense over a reasonable period of time with corresponding reductions in the rate base.

66 Pa. C.S. § 1327(a).

For the reasons detailed below, we agree with the ALJ's recommendation to deny the Company's request to include $2,437,305 in rate base to reflect the amount beyond the depreciated original cost that it paid the Borough to acquire the Phoenixville Water System, that is, that portion of the Borough's extraterritorial water system. R.D. at 43-44.

Our review of the record leads us to conclude that Aqua failed to demonstrate that the proposed acquisition adjustment related to the Phoenixville Water System satisfies the requirements of Section 1327(a). As noted, none of the Parties have disputed that Aqua has satisfied Section 1327(a)(1)-(2) and (4)-(8).[16] Thus, the contention among the Parties centers on Section 1327(a)(3) and (9), and particularly on Section 1327(a)(3)(v), which requires a finding by the Commission that "evidenc[es] the inability of the small water or sewer utility to furnish or maintain adequate, efficient, safe and reasonable service and facilities" at the time it was acquired by the acquiring utility. For the reasons discussed in more detail below, we find that the Company failed to meet its burden of proof of providing sufficient unrebutted evidence to demonstrate that the proposed positive acquisition adjustment should be included in rate base.

I&E and the OCA disputed the facts presented by the Company in response to Section 1327(a)(3), and particularly, Section 1327(a)(3)(iv). Section 1327(a)(3) specifically requires that Aqua must first provide sufficient evidence showing that "the

[16] We disagree with the Company's statement that none of the Parties disputed that the Company has satisfied Section 1327(a)(9). The Company's statement implies that no one objected to the requirement that "the excess of the acquisition cost over the depreciated original cost will be added to the rate base to be amortized as an addition to expense over a reasonable period of time with corresponding reductions in the rate base." However, because I&E and the OCA are of the opinion that the Company has not met its burden of proving that the Borough's water system was a troubled system prior to its acquisition pursuant to Section 1327(a)(3) requirement, it stands to reason that I&E and the OCA also dispute that Aqua has satisfied the requirement of Section 1327(a)(9).

public utility, municipal corporation or person from which the property was acquired was not, at the time of acquisition, furnishing and maintaining adequate, efficient, safe and reasonable service and facilities." Section 1327(a)(3) further requires that the evidence presented to illustrate that the Borough was a troubled water system must "include, but not be limited to, any one or more" of the following:

> (i) violation of statutory or regulatory requirements of the Department of Environmental Resources or the commission concerning the safety, adequacy, efficiency or reasonableness of service and facilities;
>
> (ii) a finding by the commission of inadequate financial, managerial or technical ability of the small water or sewer utility;
>
> (iii) a finding by the commission that there is a present deficiency concerning the availability of water, the palatability of water or the provision of water at adequate volume and pressure;
>
> (iv) a finding by the commission that the small water or sewer utility, because of necessary improvements to its plant or distribution system, cannot reasonably be expected to furnish and maintain adequate service to its customers in the future at rates equal to or less than those of the acquiring public utility; or
>
> (v) any other facts, as the commission may determine, that evidence the inability of the small water or sewer utility to furnish or maintain adequate, efficient, safe and reasonable service and facilities;

66 Pa. C.S. § 1327(a)(3).

As noted, *supra*, Aqua provided responses to Items (i) – (v) in its checklist in Aqua Exhibit 3-A. With regard to Item (i), the Company indicated that the Borough did not have any statutory or regulatory violations of the Department of Environmental

Resources (now the DCNR and the PADEP) at the time of acquisition. With regard to Item (ii), the Company indicated that there were no Commission findings to show that the financial, managerial, or technical ability of the Borough was inadequate. With regard to Item (iii), the Company indicated that there are no Commission findings to show that there is a present deficiency concerning the availability of water, the palatability of water or the provision of water at adequate volume and pressure. With regard to Item (iv), the Company indicated that there were no findings by the Commission to show that, because of necessary improvements to its plant or distribution system, the Borough cannot reasonably be expected to furnish and maintain adequate service to its customers in the future at rates equal to or less than those of the acquiring public utility. And with respect to Item (v), which is the contested item here, the Company indicated, as discussed above, that at the time of acquisition, the Borough was unable to furnish or maintain adequate, efficient, safe and reasonable service and facilities because: (a) the Borough was manually reading residential and commercial meters; (b) non-revenue water was estimated to be at 68%; and (c) 30% (32/105) of the Borough of Phoenixville's system hydrants needed to be repaired or replaced.

In the Recommended Decision, the ALJ stated that the only evidence proffered by the Company to demonstrate the acquired water system was troubled at the time of acquisition involved: (1) manually reading meters; (2) 68% unaccounted-for water; and (3) a need to repair or replace 32 out of 105 fire hydrants. R.D. at 42. The ALJ agreed with I&E and the OCA in finding that the evidence submitted by the Company was vague and does not provide sufficient evidence that the Borough was failing to render reasonable and adequate service to its extraterritorial customers at the time it was acquired by Aqua. The ALJ determined that the manual meter readings and hydrant replacement primarily are routine maintenance matters not related to troubled water companies that indicate simply that Aqua is fulfilling its role as the new owner of the system. With regard to the estimated 68% unaccounted-for water, the ALJ stated that, while the amount of unaccounted-for water is a concern and should be addressed, there may be a number of factors that contribute to the loss of water, but those factors alone, also do not support a conclusion that the service rendered by the Borough was inadequate within the meaning of Section 1327.

In its Exceptions, the Company maintains its argument that the manual meter readings, the need to replace 32 out of 105 hydrants, and the high level of unaccounted-for water are sufficient reasons to prove that the Borough was failing to render reasonable and adequate service at the time of the acquisition, and that the ALJ attempted to sidestep these facts in her Recommended Decision. We disagree with the Company. In our opinion, the ALJ appropriately ruled that the Company has not presented sufficient evidence to demonstrate that the Phoenixville Water System acquisition was necessary because the Borough was unable to render reasonable and appropriate service to customers at the time it was acquired by Aqua. We agree with the ALJ that the three items proffered by the Company in response to Section 1327(a)(3)(iv) are vague and not convincing. In our view, the Company failed to present substantial evidence pursuant to Section 1327(a) that the Borough was not maintaining reasonable service and thus, Aqua was not entitled to an acquisition adjustment presumption. In addition, the evidence presented by I&E and the OCA was sufficient to rebut the evidence presented by the Company.

The simple fact that the Borough's territorial customers were subsidizing service to the Borough's extraterritorial customers is not tantamount to the provision of unreasonable or inadequate service. Furthermore, the Company offered no convincing record evidence such as the number and type of customer complaints that were filed prior to or at the time of the acquisition or any proof to indicate whether the quality of the water or other services performed by the Borough were inferior and similar to those issues normally experienced by a troubled water company.

The Company also argues in its Exceptions that the ALJ did not "analyze or even acknowledge" that Phoenixville's territorial customers were subsidizing the service provided to extraterritorial customers, and the defense of a base rate filing had deterred it from seeking rate relief to invest in its system. We disagree with the Company that the ALJ did not acknowledge this issue. Our review of the Recommended Decision indicates that the ALJ acknowledged the subsidization of water service to the Borough's extraterritorial customers by the Borough's territorial customers on page 41 of the Recommended Decision. The ALJ reasoned, however, that the issue was not pertinent to the relevant inquiry. In this regard, we agree with I&E's position in its Reply Exceptions that, in this particular proceeding, the subsidization issue is irrelevant for the purpose of casting the Borough as a troubled water company. Rather, the subsidization issue is a rate structure concern internal to the Borough.

The Commission has handled numerous troubled water system acquisitions. Stated plainly, it generally is known at the time of the acquisition whether the water system to be purchased is a troubled system and it is often stated to be such and acquired pursuant to relevant statutory provisions. In this instance, nothing in the record demonstrates that the Borough was operating a troubled water system. The record reflects that the primary reason for the acquisition in this case was the Borough's desire to be relieved of Commission jurisdiction so that it could avoid the high costs the Borough would incur in filing rate cases with the Commission for its extraterritorial water system. The important matter here is whether the customers in the acquired portion of the Borough's system were receiving inferior service or whether the Company was not able to properly maintain the system facilities. The fact that the Borough chose to subsidize its extraterritorial customers with its territorial customer revenues rather than to file a rate case with the Commission to increase the rates for its extraterritorial customers, is not convincing evidence of the acquired water system being troubled.

We determine that the Company's arguments regarding manual meter reading, relatively high unaccounted-for water levels, and hydrant repair/replacement issues do not rise to the level of rendering the Phoenixville Water System "troubled at the time of acquisition." *See* Aqua R.B. at 13. The Company discusses at length its examination of the acquired assets post-acquisition and its findings of inadequacies. Aqua also vehemently argues against the I&E position that a "known or knowable" system flaw would render an acquisition adjustment claim under Section 1327 unavailable – making the statutory provision effectively a nullity. Aqua Exc. at 17.

We observe that recent orders of this Commission have directed acquiring utilities to present evidence supporting the inclusion of acquired assets in rate base and any claims of a Section 1327 acquisition adjustment be made in the first base rate case following application approval. *See e.g.*, *Application of Columbia Water Company* Docket Nos. A-2021-3027134 and S-2021-3027145 (Order entered February 3, 2022). Thus, an acquiring utility is not prohibited from seeking an acquisition adjustment and enjoying the rebuttable presumption that such an adjustment should be made, should it: (1) discover system deficiencies; and (2) present sufficient evidence that establishes sufficiently that the acquired system was troubled at the time of acquisition. Section 1327 allows for this. In our view, an adequate measure of evidence simply was not presented by Aqua in the instant matter, when the underlying history of the sale is considered, and the discovered system inadequacies are evaluated.

The Company also filed Exceptions arguing that the Commission should approve its acquisition adjustment because "the Commission had previously ***directed*** Phoenixville to avail itself of an acquisition to alleviate these burdens."[17] Aqua Exc.

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[17] In its Main Brief, Aqua also incorrectly submitted that "the Commission imposed a regulatory requirement that Phoenixville sell the assets used to serve the extraterritorial customers, if it wanted to avoid the regulatory burdens associated with the Commission's jurisdiction." Aqua M.B. at 20 (emphasis provided).

at 16. It appears that Aqua filed this Exception in support of its position that the Borough was not providing adequate service. However, as the OCA noted in its Replies to Exceptions, it is important to note that this Commission never "*directed*" the Borough to sell its extraterritorial assets. OCA R. Exc. at 2. In the *Phoenixville Petition Order*, it is clear that we only suggested that the sale of the extraterritorial water system was a viable option for the Borough to consider:

> Finally, the Commission would be remiss if we did not acknowledge Phoenixville's concern regarding the regulatory "burden" related to Commission jurisdiction. However, the Commission believes these so-called "burdens" are justifiable and if reasonable, recoverable from ratepayers. Commission oversight provides voiceless extraterritorial customers with service protections and it ensures reasonable rates that will provide for safe and reliable service over the long term. Similarly, the Commission would also be remiss if we did not acknowledge that unlike in the prior municipal corporation cases, there are viable options for the Borough, namely, PAWC's provision of public utility service in Upper Providence Township and Aqua Pennsylvania's provision of public utility service in Schuylkill Township. In conclusion, Phoenixville clearly has options to these perceived regulatory "burdens" which may prove beneficial to explore.

Phoenixville Petition Order at 7-8. Notwithstanding Aqua's mischaracterization of the Commission's Order, we are of the opinion that even if the Commission had "directed" the Borough to sell its unwanted assets, the Company's argument does not support its position that the Borough was not providing adequate water service and, thus, the acquisition cost beyond the depreciated original cost should be included in rate base. We agree with the ALJ that the Commission's comment to the Borough regarding a possible acquisition does not justify Aqua's decision to pay more than book value for the Phoenixville Water System. R.D. at 43.

In accordance with the above discussion, we shall deny the Company's Exception No. 2 and adopt the ALJ's recommendation that removes $2,437,305 from Aqua's rate base and makes the concomitant adjustments to the accrued depreciation reserve and annual amortization expense, which is expressed as a depreciation expense in this filing. Thus, the Company's claimed depreciation expense will be reduced by $121,865. These adjustments are reflected in Table II – Water, which is included in the rate tables that outline the Commission Tables Calculating Allowed Revenue Increase, which are attached to this Opinion and Order.

C. Additions to Rate Base – Cash Working Capital and Material & Supplies

1. Positions of the Parties

CWC is the capital requirement arising from the difference between: (1) the lag in the receipt of revenue for rendering service; and (2) the lag in the payment of cash expenses incurred to provide that service. R.D. at 44.

The Company's CWC claims for its water and wastewater operations include the working capital that is necessary for its O&M expense, taxes, and interest.[18] *Id.* The Company claimed a CWC amount of $1,736,000 for its water operations[19] and a CWC amount of $550,000 for its wastewater base operations.[20] *Id.*

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[18] *See* Aqua Exhibit 1-A(a), Schedule G-5; *see, e.g.*, Aqua Exhibit 1-B(b), Schedule G-5. Schedule G-5 in Exhibits 1-C through 1-G reflect the CWC amounts claimed for each of the individual wastewater operations claimed in this proceeding.

[19] Aqua Exh. 1-A(a), Schedule G-5.

[20] Aqua Exh. 1-B(b), Schedule G-5.

No Party challenged the Company's lead/lag study[21] or its calculation of: (a) the average lag days in payment of expenses, taxes, or interest; (b) the average lag day in receipt of revenues; or (c) the average lag days between payment of expenses and receipt of revenue.[22] *Id.*

However, I&E recommended an adjustment to the CWC only for the water operations based on its recommended adjustments to revenue, O&M expenses, and taxes.[23] *Id.* I&E did not recommend any adjustments to wastewater base operations, or any individual wastewater operations because the proposed adjustments did not result in material changes to the respective CWC claims. R.D. at 44-45 (citing I&E St. 1 at 30).

The OCA's proposed adjustments to CWC were initially limited to the interest component of CWC. R.D. at 45 (citing OCA St. 1 at 24-25). However, the OCA subsequently revised its recommendations to reflect updates of operating expenses based on the OCA's proposed adjustments to operating expenses. *Id.* (citing OCA St. 1-SR at 12).

Aqua adjusted its claims for CWC based on the OCA's recommended adjustments to rate base, O&M expenses and taxes. The pertinent tables in the Appendix of the Recommended Decision reflect those adjustments. R.D. at 45.

Aqua also included an addition of $7,672,303 for materials and supplies to its water operations rate base. R.D. at 45 (citing Aqua St. 1 at 27; Aqua Exh. 1-A, Sch. G-4). This amount was developed by averaging the monthly balances in the M&S

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[21] *See* Aqua St. 1 at 27 (describing the results of the lead/lag study).

[22] *See, i.e.*, I&E St. 1 at 30 (agreeing with the Company's use of the lead/lag study method).

[23] I&E St. 1 at 30-31; *see also* Aqua St. 1-R at 10.

account for water operations for the thirteen months ended March 31, 2021.[24] Aqua's wastewater filing includes a Schedule G-4, but "Aqua PA does not maintain a significant amount of standby materials and supplies for wastewater operations and, therefore, material and supplies [for wastewater operations] are expensed as they are purchased." Aqua St. 1 at 27.

No Parties challenged the Company's claim for an addition to rate base for materials and supplies.

2. Recommended Decision

The ALJ recommended that the Company's claim for CWC be adopted, as adjusted by the Company, to reflect the recommended adjustments by I&E and the OCA to rate base, O&M expenses, and taxes. The ALJ also adopted the Company's claim for an addition to rate base for M&S. R.D. at 45. The claims and pertinent adjustments recommended by the ALJ are reflected in the rate tables included in the Appendix to the Recommended Decision. A description of each of the tables is included on the first three pages of the Appendix.

3. Disposition

None of the Parties filed Exceptions regarding the ALJ's recommendation on the Company's remaining proposed adjustments to its plant in service. We find the ALJ's recommendation to be reasonable and shall adopt it. As will be discussed in more detail in Section VIII.M of this Opinion and Order, *infra,* regarding the Company's expense claims, a net increase of $275,473 will be applied to the CWC component of

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[24] Aqua St. 1 at 27.

Aqua's water rate base. This figure reflects, in part, our downward adjustment to O&M expenses of $1,900,892.

Additionally, a net increase of $362,667 will be applied to the CWC component of Aqua's wastewater rate base, which reflects, in part, our downward adjustment to wastewater O&M expenses of $232,643. This is broken down as follows: (1) a net increase to the CWC component for Wastewater-Base of $216,340, which reflects, in part, our downward adjustment to O&M expenses of $150,101; (2) a net increase to the CWC component for Wastewater-Limerick of $76,673, which reflects, in part, our downward adjustment to O&M expenses of $27,778; (3) a net increase to the CWC component for Wastewater-East Bradford of $9,669, which reflects, in part, our downward adjustment to O&M expenses of $7,802; (4) a net increase to the CWC component for Wastewater-Cheltenham of $54,249, which reflects, in part, our downward adjustment to O&M expenses of $16,469; (5) a net increase to the CWC component for Wastewater-East Norriton of $24,706, which reflects, in part, our downward adjustment to O&M expenses of $14,318; and (6) a reduction to the CWC component for Wastewater-New Garden of $18,970, which reflects, in part, our downward adjustment to O&M expenses of $16,175.

In making the above adjustments, we have applied the same methodology utilized by Aqua and the ALJ and agreed upon by I&E and the OCA. Additionally, these adjustments are reflected in Table II-Adjustments in each of the sets of Commission Tables Calculating Allowed Revenue Increase that are attached in the Appendix to this Opinion and Order.

D. Deductions from Rate Base – Customer Advance for Construction, Contributions in Aid of Construction and Accumulated Deferred Income Tax (ADIT)

1. Positions of the Parties

"A customer advance for construction or 'CAC' is funds paid to a utility for an extension of service that is refunded over time to the applicant for service." Aqua St. 2-R at 9. Similarly, "[c]ontributions in aid of construction or 'CIAC' are amounts furnished by applicants for facilities that may not be subject to a refund." Aqua M.B. at 33; Aqua St. 2-R at 9. Both CAC and CIAC are treated as a reduction to a utility's rate base.

With respect to its water operations, the Company's claim for CAC and CIAC[25] reduced rate base by ($178,784,735). R.D. at 45; Aqua Exh. 1-A, Sch. G-6. With respect to wastewater base operations, the Company's claim reduced rate base by ($20,965,154). Aqua Exh. 1-B, Sch, G-6.[26] Although the OCA initially proposed adjustments to CAC and CIAC, those proposals were subsequently withdrawn. OCA M.B. at 23; OCA R.B. at 9.

Additionally, Aqua claimed a total of $392,515,121 for water and $9,356,312 for wastewater in ADIT.[27] R.D. at 46. These amounts included normalized ADIT and the unamortized balance of excess ADIT resulting from various federal income tax rate reductions. Aqua St. 8 at 14. In rejoinder testimony, Aqua identified an

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[25] Schedule G-6 of Aqua Exhibits 1-A and 1-B contain the Company's proposed reductions to rate base for CAC and CIAC.

[26] No adjustments for CAC and CIAC were included in Exhibits 1-C through 1-G.

[27] *See* Aqua St. 8 at 14; *see also* Aqua Exh. Nos. 1-A(a) through 1-G(g), Sch. G-7.

additional $6.1 million to be deducted from water rate base associated with the Company's claim regarding the treatment of uncertain tax positions in computing the flow-through deduction for tax repairs (FIN 48 adjustment). R.D. at 46; Aqua St. 8-R at 7; Aqua St. 8-RJ at 3. This adjustment was reflected by Aqua in its rate case tables attached to its Main Brief.[28]

The OCA accepted the additional rate base deduction associated with uncertain tax positions, even though the OCA continued to oppose the Company's treatment of uncertain tax positions in computing the flow-through deduction for tax repairs. R.D. at 46; OCA St. 1-SR at 13-15.

2. Recommended Decision

The ALJ accepted Aqua's treatment of uncertain tax positions in computing the flow-through deduction for tax repairs. The ALJ noted that any other adjustments to ADIT as a result of other rulings are accounted for in the rate tables included in the Appendix to the Recommended Decision. R.D. at 46.

3. Disposition

No Party filed Exceptions on this issue. Finding the ALJ's recommendation to be reasonable, we adopt it without further comment.

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28 *See* Aqua Table I Water, Column "Company Adjustments."

VII. Revenues and Revenue Requirement

A. Revenue Requirement

A utility's revenue requirement represents the total revenue that the utility needs to collect through the rates charged to the public to cover its cost of service. *See* https://www.puc.pa.gov/General/publications_reports/pdf/Ratemaking_Guide2018.pdf, accessed on March 18, 2022, (*PUC Rate Case Handbook*) at 102. The formula to calculate the utility's revenue requirement is set forth, as follows:

RR=T+E+D+(RB x ROR)

Where: RR=Revenue Requirement
T=Taxes
E=Operating Expense
D=Depreciation Expense
RB=Rate Base
ROR=Overall Rate of Return

I&E M.B. at 42, n.169. The central issue in a base rate case involves identifying the appropriate cost of service, or revenue requirement, for the company, in this case Aqua.[29] *PUC Rate Case Handbook* at 102.

1. Positions of the Parties

Aqua's final proposed revenue requirement on a total Company basis was approximately $644,073,506, representing a proposed revenue increase of $96,990,325 over *pro forma* revenues at present rates of $547,083,180. After allocating a portion of

[29] We have discussed the Company's rate base, *supra,* and will discuss the remaining components of the Company's Revenue Requirement formula in the sections that follow.

the wastewater revenue requirement to water customers, this consisted of a proposed water revenue requirement of $595,496,015, representing a proposed revenue increase of $85,489,328 over water revenues at present rates of $510,006,687; and a proposed wastewater revenue requirement of $48,577,490, representing a proposed revenue increase of $11,500,997 over wastewater revenues at present rates of $37,076,493. Aqua M.B. at Appendix F, Water and Wastewater Revenue Requirement – Summary.[30]

I&E recommended a revenue requirement of $584,241,297 for Aqua, on a total company basis. I&E's proposal would result in a total revenue increase of approximately $33.9 million over revenues at present rates of $550,331,987. After allocating a portion of the wastewater revenue requirement to water customers, this consisted of a water revenue requirement of $530,478,098, representing an increase of approximately $17.223 million to the Company's water revenues of $513,225,494 at present rates; and a wastewater revenue requirement of $53,763,149, representing an increase of approximately $16.687 million to the Company's wastewater revenues of $37,076,443 at present rates. I&E M.B. at 5; M.B., Appendix A, Table VII-Water-Act 11 Allocation.

The OCA proposed a final revenue requirement of $549,967,611 on a total Company basis, representing a revenue reduction of approximately $12.142 million. OCA M.B. at 16; Appendix A, Summary Table.

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[30] As previously noted, the Company stated in the body of its Main Briefs that its final revenue increase request was approximately $97.6 million, which consisted of a claimed increase in water revenues of $86.118 million and a claimed increase in wastewaters revenues of approximately $11.566 million. Aqua M.B. at 2. However, Appendix F, Water and Wastewater Revenue Requirement – Summary, which is set forth in the Company's Main Briefs, shows a final proposed increase of $85,489,328 in water revenues and $11,500,997 in wastewater revenues, representing a total combined requested revenue increase of approximately $96,990,325.

Although CAUSE-PA did not propose a specific revenue requirement in this proceeding, it stated that it supported and adopted the position of the OCA. CAUSE-PA M.B. at 12.

2. Recommended Decision

The ALJ recommended an overall revenue requirement of approximately $582.2 million for Aqua on a total Company basis, based on the various adjustments she adopted in her Recommended Decision, resulting in an overall distribution revenue increase of approximately $31.9 million. After allocating a portion of the wastewater revenue requirement to water customers, the ALJ's recommendation consisted of: (1) a revenue requirement of $528.4 million for Aqua's water service, representing an increase of approximately $15.2 million over *pro forma* present rate water revenues; and (2) a revenue requirement of $53.8 million for Aqua's wastewater service, representing an increase of approximately $16.7 million over *pro forma* present rate wastewater revenues. The ALJ's recommendation represented an increase of approximately 2.97% in water operating revenue and an increase of approximately 45% in wastewater operating revenue. R.D. at 1, 140, Appendix Table Act 11 – Water and Wastewater Revenue Requirement - Summary.

3. Disposition

Based upon our findings regarding certain inputs to Aqua's rate base, *supra,* and to Aqua's revenues, expenses, cost of common equity, and overall rate of return, discussed, *infra,* we shall approve an overall revenue requirement of $617,476,255, on a total company basis, which will result in a maximum allowed overall distribution revenue increase of $69,251,169, on an annual basis. After allocating a portion of the wastewater revenue requirement to Aqua's water customers, we shall approve: (1) a revenue requirement of $561,658,784 for Aqua's water service, representing a revenue increase of $50,510,192, on an annual basis; and (2) a revenue requirement of $55,817,471[31] for Aqua's wastewater service, representing a revenue increase of $18,740,978,[32] on an annual basis. These amounts are depicted on Table Act 11 Water and Wastewater Revenue Requirement – Summary, which is part of the Commission Tables Calculating Allowed Revenue Increase that are attached to this Opinion and Order.

B. Rider DRS Contracts

1. Positions of the Parties

Aqua proposed updated FPFTY *pro forma* revenues at present rates as set forth in Schedule B-1 of Aqua Exhibits 1-A(a) through 1-G(g). As a part of its direct case on revenue requirement, Aqua included an explanation of the basis for a number of water resale contracts charging discounted rates pursuant to Aqua's tariff Rider DRS – Demand Based Resale Service (Rider DRS). *See* Tariff Water No. 3, Original Page 20. Aqua noted that "Rider DRS is available to existing or new customers that intend to purchase water from the Company for resale and have a viable competitive alternative to service from the Company." Aqua St. 2-R at 11. Customers that can satisfy the requirements of Rider DRS may qualify for customer-specific contracts at

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[31] As set forth in Table Act 11 – Water and Wastewater Revenue Requirement – Summary, which is included in the Commission Tables Calculating Allowed Revenue Increase, attached to this Opinion and Order, this amount consists of the following individual wastewater revenue requirements: $25,849,065 for Wastewater-Base Operations, $7,249,205 for Wastewater-Limerick, $1,663,639 for Wastewater-East Bradford; $12,044,410 for Wastewater-Cheltenham, $4,582,750 for Wastewater-East Norriton, and $4,428,399 for Wastewater-New Garden.

[32] This amount consists of the following individual allowed annual revenue increases: $6,837,304 for Wastewater-Base Operations, $3,270,632 for Wastewater-Limerick, $649,070 for Wastewater-East Bradford; $4,785,671 for Wastewater-Cheltenham, $1,658,983 for Wastewater-East Norriton, and $1,539,319 for Wastewater-New Garden. *See Id.*

discounted rates designed to maintain sales that would otherwise be lost to water service alternatives. *Id.*

Rider DRS further provides that, in order to qualify for discounted rates, a customer must have a competitive alternative:

> The Company shall require documentation to establish, to the Company's satisfaction, the existence of a competitive alternative. Such documentation may include, but is not limited to, an affidavit of the customer or, if the customer is a corporation, an affidavit of one or more of its officers.

Tariff Water No. 3, Original Page 20.

In the Joint Petition for Settlement (2018 Settlement) approved by the Commission in the *Aqua 2018 Rate Case*, the Company agreed to provide "documentation of the existence of a viable competitive alternative to water service provided by the Company for the following Rider DRS customers and any new Rider DRS customers added after the date of this [2018 Settlement]":

Rider DRS Customers

Chemung County Industrial Development Agency [(Chemung)]
New Wilmington Municipal Authority [(New Wilmington)]
Warwick Township Water and Sewer Authority [(Warwick)]
Borough of Sharpsville [(Sharpsville)]
City of Hubbard [(Hubbard)]
Horsham Water Authority [(Horsham)]
Schwenksville Borough Authority [(Schwenksville)]

2018 Settlement at ¶ 24.

Aqua also agreed in the 2018 Settlement "to date each competitive alternative analysis that is submitted regarding the above Rider DRS customers or new Rider DRS customers, and provide dates for when the competitive alternative analysis was last considered, if applicable." 2018 Settlement at ¶ 25. In addition, Aqua agreed to provide "a competitive alternative for the rates charged to [Aqua Ohio's Masury Division (Masury)] area customers in its next water base rate filing." 2018 Settlement at ¶ 26. Finally, it was noted in ¶ 27 of the Joint Petition that any party to same "reserves the right to review and challenge any contract and/or rate in future Aqua base rate filings, or in subsequent litigation related to this proceeding."

I&E reviewed the updated information provided by Aqua regarding the Rider DRS customers and found that the documentation was inadequate to demonstrate a competitive alternative for certain customers. Thus, I&E proposed adjustments related to the "cancellation" of certain negotiated contracts that provide for sales for resale of water.[33] *See* I&E St. 4-SR at 17-18, I&E M.B. at 25-29.

I&E argued that several of the contracts do not qualify for the tariff discount and that these customers should pay full tariff rates when the rates resulting from this base rate case become effective. Specifically, I&E contended that resale customers are only eligible for discounted rates in a negotiated contract upon demonstration of the existence of a "viable competitive alternative" to service by the Company, and that the customer or prospective customer intends to select that alternative. In addition, I&E argued that unless and until the contract between Aqua and Masury – which was filed with the Commission as an affiliated interest agreement in November 2021 – is approved, Masury should be billed at full tariffed rates. I&E St. 4-SR at 20, I&E M.B. at 28.

[33] I&E originally sought to have additional discount contract customers moved to full tariff rates but withdrew its requests in surrebuttal testimony based upon the Company's demonstrated evidence of available competitive alternatives.

2. Recommended Decision

The ALJ agreed with I&E that the documentation supplied by many of the discount rate customers was insufficient to demonstrate the existence of a competitive alternative. R.D. at 47. The ALJ reasoned that while an analysis of a competitive alternative need not be complex, more is required than simply a self-serving statement that competitive alternatives exist. The ALJ concluded that it is not burdensome to require the customer to include at least some description of the available alternatives and that it is not reasonable for Aqua to be satisfied by a dearth of information. The ALJ thus recommended that the Chemung and Horsham customers should be subject to Aqua's full tariffed rates. R.D. at 48.

The ALJ also agreed with I&E that the contract with New Wilmington does not comply with the terms of Rider DRS, and likewise should be subject to full tariff rates. *Id.* The ALJ determined that the only competitive alternative identified in the documentation supporting the discounted sale rate for the Borough of Sharpsville was the potential construction of an expensive new water treatment plant. The ALJ found that there was no evidence that this alternative is financially viable or that Sharpsville could purchase water from other sources and, accordingly, found that the contract with the Borough of Sharpsville does not qualify for Rider DRS. *Id*. at 48-49.

In contrast, the ALJ found that the documentation provided by the Executive Director of Schwenksville Borough is sufficient to demonstrate that the competitive contract satisfies the language of Rider DRS regarding the availability of competitive alternatives. Although not in the form of an affidavit, the ALJ determined that the letter is sufficiently reliable for the purpose of determining Schwenksville's qualification for Rider DRS. The ALJ concluded that it is reasonable for the Company to be satisfied by this description of a competitive alternative for the purpose of offering discounted service. *Id*. at 49.

In addition, the ALJ noted that Aqua provides water to Masury under a special tariff rate, that Aqua and Masury have negotiated a new contract under Rider DRS, but that the contract is an affiliated interest agreement that must be approved by the Commission pursuant to 66 Pa. C.S. § 2101, *et. seq*. R.D. at 49. Explaining that the agreement was filed with the Commission on November 30, 2021, and is pending a decision, the ALJ reasoned that, until the Commission makes a determination regarding the agreement, Masury should be charged full tariff rates, because doing otherwise would be premature. The ALJ recommended that Aqua's present rate revenues should be increased accordingly. R.D. at 49-50.

In summary, the ALJ recommended that the Commission direct Aqua to charge Sharpsville, Chemung, Horsham, and New Wilmington the full tariffed rates specified in Aqua's rate schedules upon the effective date of new base rates in this proceeding. She noted that this was without prejudice to the affected customers' ability to provide specific supporting documentation to Aqua that would satisfy the requirements of Rider DRS, including evidence that the affected customer has a viable competitive alternative and intends to select that alternative in the absence of a discounted rate. R.D. at 49. The ALJ also recommended that Masury be charged full tariff rates pending Commission consideration of the filed affiliated agreement. *Id*. at 46-50.

3. Aqua Exception No. 3, I&E Exception No. 1, and Replies

In its Exception No. 3, Aqua claims that the ALJ erroneously directed the Company to cancel certain Rider DRS contracts and charge those customers full tariff rates. The Company notes that the contracts were negotiated in good faith, in some cases, many years ago, and that cancellation of these arrangements could likely negatively impact current Aqua customers, create unnecessary litigation, and force local governments to build infrastructure, which they previously relied upon as being unnecessary. Aqua Exc. at 18-20.

Aqua claims that Rider DRS permits Aqua to enter into customer specific contracts at prices designed to maintain sales that would otherwise be lost to water service alternatives for customers that can satisfy the requirements of the rider. Aqua M.B. at 38-40. Aqua submits that the ALJ erred by agreeing with I&E's focus on the requirement that such customers must have a "competitive alternative" to qualify for the rate discount. Aqua notes that the contracts at issue include those between Aqua and Sharpsville, Schwenksville, Chemung, Horsham, and New Wilmington. Aqua Exc. at 18-21 (citing I&E St. 4-SR at 18). Aqua also disagrees with the ALJ's conclusion that charging Masury discounted rates is "premature." Aqua Exc. at 19 and 21-22.

Aqua claims that the ALJ's recommendations ignore the specific language of Rider DRS, which provides that:

> The Company shall require documentation to establish, to the Company's satisfaction, the existence of a competitive alternative. Such documentation <u>may include, but is not limited to</u>, an affidavit of the customer or, if the customer is a corporation, an affidavit of one or more of its officers.

Tariff Water No. 3, Original Page 20 (emphasis added). Aqua Exc. at 19.

Emphasizing that the Company is required to adhere to its tariff pursuant to 66 Pa. C.S. § 1303, Aqua asserts that the ALJ's conclusions undermine the Company's ability to essentially exercise its judgment in evaluating the information supplied by potential contracting parties, and thus, adhere to its tariff as it is obligated to do under the Code. Aqua Exc. at 19. Additionally, Aqua argues that the ALJ disregarded the basis upon which the parties entered into these contracts and that her recommendation undermines the benefits these contracts provide to other customers. Aqua Exc. at 19-20 (citing Aqua M.B. at 41-42). Aqua claims that, by recommending that the Commission adopt the position of I&E, the ALJ supports I&E's "second guessing of documentation, contracts and decisions made by entities in the past." Aqua Exc. at 20. Aqua avers that the ALJ's recommendation is erroneous because it "ignores the realities of these long-term contracts and seeks to analyze them in a vacuum, divorced from the specific facts and circumstances that existed at the time the contracts were entered into." *Id.* Aqua further claims that the Recommended Decision fundamentally alters the good faith, arms-length negotiations of the parties when they entered into the contracts over a decade ago. Aqua Exc. at 20 (citing Aqua M.B. at 42). Aqua submits that this ultimately eliminates approximately $974,405 in benefits to other existing Aqua customers.[34] *Id.* (citing Aqua M.B. at 38-39).

Aqua next addresses the recommendations specific to each of its contracts with Chemung, Horsham, Sharpsville, New Wilmington, and Masury. Taking the Chemung, Horsham, and New Wilmington contracts together, Aqua claims that the ALJ erroneously concludes that the documentation provided by Chemung and Horsham is only "a self-serving statement that competitive alternatives exist" and that "[i]t is not reasonable for Aqua to be satisfied by so little information." Aqua Exc. at 20. Aqua submits that the statement in the Chemung contract is not "self-serving," but rather, it is a legally binding representation by this municipality, that forms the basis for the contract itself. *Id.* (citing Aqua M.B. at 47). Aqua argues that effectively, the ALJ appears to insinuate that the representations of a municipal entity that binds itself to a long-term contract based thereon is not to be trusted. Aqua asserts that there is no support for such a finding in the record. Aqua Exc. at 20.

Aqua insists that it demonstrated that Horsham has existing interconnections with the Company and another water provider, in addition to wells located throughout its own system. Aqua Exc. at 20-21 (citing Aqua M.B. at 48). Aqua argues that the Recommended Decision ignores these alternative supplies, and further

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[34] Aqua claims that this is the sum of the benefits of the contracts associated with the applicable entities. Aqua Exc. at 20.

disregards the undisputed fact that Horsham could supply 100% of its water through sources other than the Company. Aqua Exc. at 20-21 (citing Aqua M.B. at 48).

With regard to New Wilmington, Aqua claims that the ALJ is in error by concluding that Aqua's contract with New Wilmington does not comply with Rider DRS. Aqua Exc. at 21. The Company claims that it demonstrated that the wheeling agreement[35] with New Wilmington provides important benefits, including enabling Aqua to provide service to a noncontiguous area of its service territory at low cost. According to Aqua, these factors make it reasonable for the Company to conclude that such a wheeling agreement does not require a competitive alternative. *Id.* (citing Aqua M.B. at 48-49).

Aqua next addresses the Sharpsville contract and asserts that the ALJ erred by retroactively concluding that the alternative identified by Sharpsville at the time it entered into the contract is not viable. Aqua Exc. at 21. Aqua asserts that the ALJ ignores other representations in the original contract by concluding that "the only competitive alternative identified in the documentation supporting the discounted sale rate was the potential construction of an expensive new water treatment plant. There is no evidence that this alternative is financially viable or that Sharpsville could purchase water from other sources." *Id*. at 21 (citing R.D. at 48-49). Aqua claims that Sharpsville also made representations at the time the contract was entered into regarding the then-existing source of supply. Aqua Exc. at 21 (citing Aqua M.B. at 44-45). Aqua asserts that this evidence conclusively demonstrates that Sharpsville was not only contemplating a new alternative to obtaining water service from Aqua, but also had an existing alternative at the time it entered into the contract. Aqua Exc. at 21 (citing Aqua

[35] Under a wheeling agreement, the Company "wheels" water to a proposed service area that is not contiguous with its distribution system. To transport the water to the proposed service area, Aqua provides water at a designated point of interconnection and then withdraws water elsewhere to serve the new service area. Aqua St. 2-R at 24.

M.B. at 44-45). Aqua adds that Sharpsville subsequently provided an affidavit that satisfies Rider DRS. Aqua Exc. at 21 (citing Aqua M.B. at 45-46). As a result, Aqua claims that the Commission should not cancel its long-term DRS contract with Sharpsville mid-term where the stated alternative at the time of contracting does not now exist precisely because of the Aqua DRS contract. *Id.* In sum, Aqua avers that Sharpsville has provided the documentation required by Aqua's tariff, and Aqua is obligated to adhere to its tariff. Aqua Exc. at 21.

Finally, Aqua asserts that the ALJ erred by concluding that the pendency of a Commission decision on the Masury contract dictates that the full tariff rate be applied to this customer unless and until the contract is approved. Aqua Exc. at 21-22. According to Aqua, the ALJ misunderstood the facts. Specifically, Aqua claims that the Recommended Decision disregards the fact that Aqua currently provides water to Masury under a special tariff rate.[36] In addition, Aqua points out that this specific agreement contains a competitive alternative analysis, as well as a sworn affidavit from Masury that it would select the alternative in the absence of the new contract. Aqua Exc. at 22 (citing Aqua M.B. at 49-50). Aqua contends that, if it is to be concluded that the Masury contract is not approved, then, rather than impute over $1 million in additional revenues from Masury as proposed by the ALJ, the Commission should remove $258,000 in revenues that will not be received from Masury. Aqua Exc. at 21 (citing Aqua M.B. at 50).

I&E replies to Aqua's assertions of error by stating that the ALJ correctly reasoned that customers who are able to satisfy the requirements of Rider DRS can enter into customer specific contracts at prices designed to maintain sales that would otherwise be lost to water service alternatives. I&E R. Exc.at 8 (citing R.D. at 47-50). I&E stresses that the key consideration under Aqua's tariff is the existence of a competitive

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[36] *See* Tariff Water – Pa. P.U.C. No. 2, Third Revised Page 12.4.

alternative. According to I&E, the ALJ correctly analyzed the evidence presented regarding each of the Rider DRS contracts and reached well-reasoned conclusions. *Id.* I&E asserts that, while Aqua had the opportunity to provide substantial record evidence to support each of the Rider DRS contracts, it failed to meet its burden regarding those contracts identified by the ALJ. Therefore, I&E submits that the Commission should reject Aqua's Exception No. 3. I&E R. Exc. at 8.

In its Exception No. 1, I&E finds fault with the ALJ's conclusion that Aqua supplied sufficient evidence to support the DRS contract between Aqua and Schwenksville. I&E Exc. at 3-4 (citing R.D. at 49). I&E submits that the ALJ erroneously found that "the documentation provided by the Executive Director of Schwenksville Borough is sufficient to demonstrate that the competitive contract satisfies the language of Rider DRS regarding the availability of competitive alternatives." I&E Exc. at 3 (citing R.D. at 49). I&E specifically disagrees with the ALJ's conclusion that, "[a]lthough not in the form of an affidavit, the letter is sufficiently reliable for the purpose of determining Schwenksville's qualification for Rider DRS." I&E Exc. at 3-4 (citing R.D. at 49). I&E also disagrees that "it is reasonable for the Company to be satisfied by this description of a competitive alternative for the purpose of offering discounted service." I&E Exc. at 4 (citing R.D. at 49). I&E asserts that the letter provided by Schwenksville does not rise to the level of an affidavit and, therefore, is not sufficiently reliable for the purpose of determining Schwenksville's qualification for a Rider DRS. I&E Exc. at 4.

I&E argues that the document provided by Aqua is merely a cover letter with no oath or affirmation, and not an affidavit or the legal equivalent of one and thus, does not meet the standard required to be considered valid documentation supporting a competitive alternative under the plain language in Aqua's tariff. I&E Exc. at 4. Therefore, according to I&E, the Commission should overturn the ALJ's recommendation, cancel the Schwenksville contract, and require Schwenksville to begin paying full tariff rates when they go into effect pursuant to this base rate proceeding. *Id.*

Aqua replies that I&E's argument disregards the plain language of Rider DRS, which permits Aqua to accept "documentation [that] <u>may include, but is not limited to,</u> an affidavit." Tariff Water No. 3, Original Page 20 (emphasis added). Aqua R. Exc. at 1-2. Aqua submits that it fully addressed I&E's claims and demonstrated that it satisfies the requirements of its tariff. Aqua R. Exc. at 1-2 (citing Aqua M.B. at 46-47, Aqua R.B. at 17-18). Aqua also argues that adopting I&E's assertion would violate the requirements of 66 Pa. C.S. § 1303, which requires Aqua's adherence to its effective tariff. For these reasons Aqua requests that I&E's exception be denied. Aqua R. Exc. at 2.

4. Disposition

At the outset, we note that adherence to tariff provisions is a statutory obligation of the utilities we regulate. 66 Pa. C.S. § 1303. We further note that when analyzing a tariff provision, like the law, we will not ignore its plain language under the pretext of pursuing its spirit. Finally, we study carefully the agreements reached by parties and commitments made in settlements brought to the Commission for its consideration and the evidence submitted in purported compliance with those settlement terms. With these governing principles in mind, we adopt, in part, and reject, in part, the recommendations of the ALJ on the DRS contract issues, as discussed more fully below.

It is useful first to repeat Aqua's obligations agreed to in the 2018 Settlement. The Company agreed to provide "documentation of the existence of a viable competitive alternative to water service provided by the Company for the following Rider DRS customers and any new Rider DRS customers added after the date of this Joint Petition" for Chemung, New Wilmington, Warwick, Sharpsville, Hubbard, Horsham, and Schwenksville. 2018 Settlement at ¶ 24.

Aqua also agreed as follows:

> 25. Aqua agrees to date each competitive alternative analysis that is submitted regarding the above Rider DRS customers or new Rider DRS customers, and provide dates for when the competitive alternative analysis was last considered, if applicable.
>
> 26. Additionally, Aqua agrees to provide a competitive alternative for the rates charged to Masury area customers in its next water base rate filing.
>
> 27. Any party to this Joint Petition reserves the right to review and challenge any contract and/or rate in future Aqua base rate filings, or in subsequent litigation related to this proceeding.

2018 Settlement at ¶¶ 25-27.

These settlement commitments by Aqua were approved as a part of the Commission's Opinion and Order in the *Aqua 2018 Rate Case*. We analyze each part of these settlement terms as context for the direct case that Aqua was to present in this, its next, base rate case.

Reviewing the 2018 Settlement language carefully, it is patently evident that under Paragraph 25, Aqua agreed to undertake a competitive alternative analysis for each existing and new Rider DRS contract, date those analyses, and indicate when the competitive alternative analysis "was last considered, if applicable." This language seems to contemplate that consideration of the competitive alternative offered by a contracting party could be undertaken periodically during the course of the contract. This concept is contrary to Aqua's claim now, in this present case, that the original validation of the availability of a competitive alternative is undertaken only at the time of contracting and it is not reviewed until the term of the contract expires.

With regard to the Masury contract, the 2018 Settlement contemplated that Aqua would "provide a competitive alternative for the rates charged to Masury area customers" in its next base rate case. This language is inartful, at best, and confusing when viewed in the context of our consideration of the Recommended Decision on the pending Masury contract and Aqua's Exceptions regarding the same. Nevertheless, we examine the evidence of record and the ALJ's recommendation on the Masury contract issue as we find it and rule on that basis.

Finally, we note that we do not have before us a recommendation or dispute regarding Aqua's contracts with Hubbard, Warwick, Downingtown Municipal Water Authority, and Bucks County Water and Sewer Authority - Bristol. I&E withdrew its opposition to these contracts based upon information supplied by the Company. *See* I&E M.B. at 25-29. I&E indicated that it did not address Aqua's contract with United Water because it was previously approved by the Commission. Our review of the record regarding these contracts indicates that even though they may provide some mutual benefit to the parties and are not detrimental to Aqua's other customers, some of them potentially do not fit strictly within the applicability standards for Rider DRS. We strongly encourage Aqua to consider the development of an appropriate tariff provision governing the unique circumstances of these contracts.

With regard to the Chemung, Horsham and Sharpsville rate discounts, we agree with Aqua that it has presented sufficient record evidence to support the discounted rates based upon the availability of competitive alternatives. Aqua's decisions to grant the discounted rates to these entities were validly based on official representations made by responsible municipal officials. For these reasons, we shall grant Aqua's Exception No. 3 with respect to its arguments regarding the Chemung, Horsham, and Sharpsville discounts and reject the ALJ's recommendations that these customers be charged full tariff rates. Based on our granting this portion of Aqua's Exceptions, the ALJ's upward adjustment of $2,983,780 to the Company's revenues, as set forth on Table II - Water in the Attachment to the Recommended Decision, will be reduced by $1,847,694.[37] Therefore, our total upward adjustment to the Company's Revenues as a result of water contract revenue is $1,136,086 (*i.e.*, $2,983,780 - $1,847,694 = $1,136,086].[38]

As for New Wilmington, however, we agree with Aqua that it must adhere to its tariff language and the applicable DRS Rider does not contain any provision for the type of "wheeling" arrangement that Aqua entered into here. Aqua's claim of "important benefits" justifying its departure from the competitive alternative requirement in Rider DRS simply does not hold water.[39] For these reasons, we deny Aqua's Exception No. 3 with respect to its arguments regarding the New Wilmington contract and adopt the ALJ's recommendation that Aqua charge New Wilmington full tariff rates. Accordingly, we shall impute $348,904 in revenues, representing the difference between $677,550 in revenues at New Wilmington's full tariff rate and $328,646 in revenues at contract rates. *See* I&E Exh. 4-SR, Sch. 1.

With regard to Masury, we acknowledge Aqua's observation that it provides service to Masury under a special tariff rate.[40] In addition, Aqua also has demonstrated that the agreement contains a competitive alternative analysis and a sworn

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[37] As we are permitting the Company to grant discounted rates to Chemung, Horsham, and Sharpsville, the associated imputed revenues added back by the ALJ of $30,944, $123,779, and $1,692,971, respectively, will be removed from the ALJ's total upward adjustment for water contract revenues.
[$30,944 + $123,779 + $1,692,971] = $1,847,694. *See* I&E Exh. 4-SR, Sch 1.

[38] Accordingly, this $1,136,086 is comprised of imputed general service revenues of $348,904 for New Wilmington and $787,182 for Masury, discussed, *infra*.

[39] We also note that consideration of the existence of competitive alternatives during the course of the contract is not explicitly prohibited by the language of Rider DRS. While it requires Aqua to consider evidence of competitive alternatives at the time of original contracting, it does not preclude Aqua from re-evaluating the contract in the event of changed circumstances.

[40] *See* Tariff Water – Pa. P.U.C. No. 2, Third Revised Page 12.4.

affidavit from Masury that it would select an alternative provider in the absence of the new contract. Aqua M.B. at 49-50. Nonetheless, we note that the new contract is pending approval by the Commission. Thus, because the new contract has not yet been ruled upon by the Commission, we deny this portion of Aqua's Exception No. 3 and include in Aqua's revenues those anticipated to be received from Masury under its special tariff rates that are currently in effect. Accordingly, we shall impute $787,182 in revenues, representing the difference between $1,045,216 in revenues at Masury's special tariff rate and $258,034 in revenues at contract rates.[41] *See* Aqua RS2 Attachment at 8; I&E Exh. 4-SR, Sch. 1.

We shall also deny I&E's Exception No. 1. The ALJ's conclusion that Aqua has met its burden to establish competitive alternatives available to Schwenksville is correct. Simply put, the language of Rider DRS does not command an affidavit from a contracting party. Aqua's acceptance of the documentation submitted by this duly formed municipal entity as sufficient and reliable is reasonable. We thus adopt the ALJ's recommendation to uphold the Schwenksville contract discount due to competitive alternatives being demonstrated as available to the customer.

C. Late Payment Charges

1. Positions of the Parties

I&E recommended an adjustment to the Company's forfeited discount revenues (*i.e.* revenues received from late payment charges). More specifically, I&E

[41] We note that although the ALJ stated that the Company should bill Masury at full tariff rates, the ALJ properly used the revenues at Masury's special tariff rate in making her upward adjustment to Aqua's water contract revenues. Therefore, our only financial modification to the ALJ's recommended adjustment for water contract revenues is our adjustment to remove the imputed general service revenues associated with Rider DRS contracts for Chemung, Horsham and Sharpsville, discussed, *supra.*

recommended that the Company's water revenues under present rates be increased to reflect $1,373,542 in late payment revenue. I&E St. 4 at 7. Additionally, I&E recommended that the Company's wastewater revenues for its New Garden system under present rates be increased to reflect $17,832 in late payment revenues. I&E St. 5 at 60.

Aqua argued that I&E's proposed recommendation for water revenues at present rates should be rejected because, in its response to filing requirement "OR6 for Water," the Company recorded "other miscellaneous revenues" totaling $1,301,938 on its books for the HTY ended March 31, 2021, which were, therefore, included in the FPFTY claim. Of this amount, the Company explained that $735,710 was attributable to late payment revenues in the HTY. Thus, Aqua submitted that I&E's claim that the Company did not include late payment revenues for the FTY and the FPFTY was incorrect. However, in reviewing I&E's proposed recommendation, the Company agreed to make an upward adjustment to increase FPFTY miscellaneous revenues by $150,172 to normalize the impact of COVID-19 on miscellaneous revenues. Aqua M.B. at 56; Aqua R.B. at 20.

I&E accepted the Company's adjustment and withdrew its recommended adjustment of $1.3 million to water revenues at present rates. I&E St. 4-SR at 3-4. Additionally, the Company agreed with I&E's recommendation to increase wastewater revenues by $17,382 for Aqua's New Garden system under present rates. Aqua M.B. at 56-57.

At the same time, I&E recommended that the Company's water revenues at proposed rates be increased by the same percent increase as the overall base rate increase granted by the Commission in this proceeding. I&E M.B. at 22-23.

Aqua countered that such an adjustment is not necessary because the Company has already reflected late payment revenues at proposed rates in its present rate adjustment. Therefore, Aqua took the position that I&E's recommended adjustment would result in the improper double counting of late payment revenues. Aqua M.B. at 56; Aqua R.B. at 21.

I&E rejoined that the Company's late payment claim under revenues at present rates is designed to project the amount of revenue the Company would receive in the FPFTY if its rates were not increased. As such, I&E insisted that Aqua's claim that it already made an adjustment for the increase in late payment revenue that would be generated under proposed rates in its present rate claim is illogical and should be rejected.

Aqua and I&E also applied their above respective positions to the Company's wastewater revenues at proposed rates. Namely, the Company asserted that it will receive the same $93,816 in late payment revenues under proposed rates for the FPFTY that it reflected under revenues at present rates, such that no adjustment to its revenues at proposed rates is necessary. Aqua St. 2-R at 30-31; I&E M.B. at 23-24.

However, I&E asserted that because late payment revenues are generally a percentage of a customer's bill, it is reasonable to expect that increasing revenue through a base rate increase will cause revenues from late payments to increase over time. Thus, I&E maintained that the Company's wastewater revenues at proposed rates should also be increased by the same percent increase as the overall base rate increase granted by the Commission in this proceeding. I&E M.B. at 24-25; I&E R.B. at 17-18.

2. Recommended Decision

The ALJ found I&E's position to be persuasive. Therefore, the ALJ recommended that the Company's late payment revenues at proposed rates, projected for the FPFTY, be adjusted for both water and wastewater accordingly. According to the ALJ, the total permitted operating revenue in this matter is inclusive of general service, forfeited discount, and other miscellaneous revenues. Thus, the ALJ further concluded that Aqua should be directed to increase general service and forfeited discount revenues by the same percentage amounts such that these revenues, when combined with other miscellaneous revenues that are not increasing, equal the total permitted operating revenue. The ALJ also recommended that Aqua be instructed to demonstrate compliance with this directive through its proof of revenues, consistent with the Commission's Regulations at 52 Pa. Code §5.592(a) regarding compliance with orders prescribing rates. The ALJ attached, as Table RevSum, an illustration of the recommended increase in forfeited discount revenues that would result from the recommended increase in general service revenues. R.D. at 51; Appendix Table RevSum.

The ALJ also explained that the revenue adjustments included in Table II - Water, as discussed in the Recommended Decision and in the Appendix thereto, resulted in a concomitant adjustment to forfeited discount revenues. The ALJ stated that if it is reasonable to assume that additional revenues result in an incremental bad debt expense, as assumed by the increase in O&M Expense indicated in Table I, Column "ALJ Revenue Increase" of each rate case table, then it also must be reasonable to assume that the Company will receive corresponding forfeited discount revenues from those customers that are causing the incremental bad debt expense by not making timely payments on their bills. The ALJ continued that concomitant forfeited discount revenue is determined by applying Aqua's proposed uncollectible account rate to the sum of other revenue adjustments. The ALJ explained that this adjustment is reflected in each rate case table in the Attachment to the Recommended Decision under Table II, Row "Concomitant Forfeited Discounts."[42] R.D. at 51-52, Appendix Table II.

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[42] However, as the ALJ did not recommend any additional adjustments to the Company's wastewater revenues, no adjustment for "Concomitant Forfeited Discounts" appears on Table II of any of the wastewater rate tables that were attached to the Appendix of the R.D.

3. Disposition

No Party filed Exceptions on this issue with regard to the ALJ's recommendation. Finding the ALJ's recommendation to be reasonable and based soundly on record evidence, we shall adopt it. Accordingly, we shall adopt the ALJ's recommendation that Aqua's claim for late payment revenues under proposed rates, for both water and wastewater, be increased by the same percentage as the overall base rate increase authorized under this Opinion and Order. In addition, we shall instruct Aqua to demonstrate compliance through its proof of revenues that will be included with the detailed calculations that accompany its tariff filing, described in Ordering Paragraph 16 of this Opinion and Order, *infra.* Similar to the ALJ in her Recommended Decision, Table RevSum, which is attached to the Appendix of this Opinion and Order, outlines the increase in forfeited discount revenues that would result from the final increase in general service revenues authorized under this Opinion and Order.

We further note that the final adjustments that we make to the Company's water revenues are included on Table II-Water-Summary of Adjustments in the Commission Tables Calculating Allowed Revenue Increase, attached to this Opinion and Order, along with the adjustments we have made to rate base, expenses, and taxes, as discussed elsewhere in those sections of this Opinion and Order. This table likewise includes an adjustment amount for "Concomitant Forfeited Discounts" based upon the uncollectible accounts factor outlined in Table IB-Water-Revenue Factor.

D. Escalation Provisions of Negotiated Water Contracts

1. Positions of the Parties

The OCA proposed that, to reflect revenue adjustments for the sale and resale contracts for the end-user negotiated rate contracts, the Company's water utility revenue for the FPFTY should be increased by $236,777 for special contract revenue.[43] OCA M.B. at 26 (citing OCA St. 1SR at 16; OCA Exh. LA-6, Sch. C-2; OCA St. 4SR at 11). The OCA noted that the escalation provisions in Aqua's contracts are tied to changes in the Consumer Price Index (CPI). The OCA argued that Aqua forecasted considerably lower inflation rates without providing a basis for their use. The OCA submitted that its recommended escalation rates using the average of the United States Office of Management and Budget's (US OMB) and the Federal Reserve's forecasted inflation rates for 2021, 2022, and 2023 were the appropriate rates to be applied in this case. OCA M.B. at 26 (citing OCA St. 4SR at 9-10; Aqua St. 2-R at 28). Thus, the OCA submitted that its inflation calculation is a more accurate and realistic depiction of what inflation levels will be in the FPFTY. OCA M.B. at 26; OCA R.B. at 12-13.

Aqua disagreed with the OCA's proposed upward adjustment, arguing that the adjustment uses different inflation factors that are inconsistent with the inflation escalation clauses in the respective contracts. Aqua R.B. at 19 (citing Aqua St. 2-R at 28). Aqua further argued that, although this rate case is based upon a FPFTY ending March 31, 2023, the OCA included forecasted inflation rates for 2023 that will not affect most of the contract rates. Aqua M.B. at 52.

[43] Initially, the OCA submitted that Aqua's negotiated contract revenue adjustment be increased $301,307. OCA St. 4SR at 11.

Aqua submitted that, contrary to the OCA's claim that the Company did not provide a basis for its adjustment factors, the escalation factors used are the same factors used to determine the General Price Level Adjustment for expense purposes. Aqua R.B. at 19 (citing Aqua M.B. at 53). Aqua explained that the Company's projection of inflation adjustments is based upon "the [Gross Domestic Product] GDP Chained Price Index" at the time the instant case was filed, which was used to calculate the General Price Level Adjustment for expense purposes. Aqua M.B. at 53. Thus, Aqua posited that for consistency, the inflation factor used to adjust certain revenues should be the same as the inflation factor used to adjust certain expenses. *Id.* Aqua added that using different escalation factors should not be permitted because it "would undermine the parties' good-faith bargain." Aqua R.B. at 19 (citing Aqua M.B. at 53).

2. Recommended Decision

The ALJ disagreed with the Company's argument that the escalation factor reasonably represents projected revenue resulting from negotiated contracts. Accordingly, the ALJ recommended that the Company's special contract revenue be increased in the FPFTY to reflect the escalation rate calculated by the OCA. R.D. at 53.

The ALJ found that the purpose of calculating the revenue requirement in a rate filing is to project revenues and expenses that can be expected in the FPFTY, which ultimately results in a reasonable and fair opportunity to earn a fair rate of return. The ALJ further found that, where such revenue is tied to a contractual escalation factor, revenue should be increased based upon a reasonable estimate of the amount of that escalation factor. The ALJ reasoned that the OCA's adjustment values are reliable and impartial because they are determined by government agencies (*i.e.*, the US OMB's and the Federal Reserve's forecasted inflation rates for 2021, 2022, and 2023). R.D. at 53 (citing OCA M.B. at 26). The ALJ observed that the OCA determined its projected CPI by averaging the forecasted CPIs for 2021, 2022, and 2023 for the Office of Management

& Budget (OMB) and the Federal Reserve. Additionally, the ALJ noted that the OCA supported higher inflation for 2021 through a November 2021 government publication containing information up to October 2021 from the Bureau of Labor Statistics. R.D. at 53.

Accordingly, the ALJ recommended that Aqua's special contract revenue be increased in the FPFTY based on the escalation rate calculated by the OCA, as reflected in Table II - Water in the Appendix of the Recommended Decision. Additionally, the ALJ noted that she did not include adjustments for the Rider DRS contracts because she recommended that Rider DRS contracts be charged the full tariff rates and "full tariff rates are not subject to an additional escalation rate." R.D. at 53. Thus, the actual upward adjustment to the Company's revenues as a result of the ALJ's recommendation was $181,350. R.D. at Appendix, Table II - Water.

3. Aqua Exception No. 4 and Replies

In its Exception No. 4, Aqua disagrees with the ALJ's conclusion to increase the Company's special contract revenue associated with the OCA's calculated negotiated water rate contracts by $236,777, to reflect the OCA's recommended escalation rates. Aqua Exc. at 22-23 (citing R.D. at 53-54; Aqua M.B. at 51-53; Aqua R.B. at 19).

Aqua argues that as a part of its contract terms, each of the contracts that would be subject to this adjustment contain an escalation provision that specifies how the rate of inflation is to be calculated for determining the annual escalation. Aqua Exc. at 23 (citing Aqua M.B. at 51). Therefore, Aqua argues that the OCA's recommendation is unreasonable and inappropriate because it effectively substitutes an escalation rate into each contract that is different from the agreed-upon escalation rate. Moreover, Aqua argues that it demonstrated that the OCA's calculated inflation rates are overstated. Aqua

Exc. at 23 (citing Aqua M.B. at 52-53). Aqua explains that the OCA includes inflation rates for 2023, which ignores that the instant rate case "is based upon a FPFTY ending March 31, 2023, and 2023 inflation rates will not affect most of the contract rates." *Id.* (citing Aqua M.B. at 52). Thus, Aqua contends that the adjustment calculation recommended by the ALJ is based upon inflation rates that will not affect the Company's revenues during the FPFTY. *Id.*

Aqua also submits that to the extent that the Commission determines that the OCA's adjustment is appropriate due to the OCA's use of more current inflation rates, the Commission should consider such inflation rates with respect to the Company's proposed General Price Level Adjustment. Aqua cites to its Exception No. 7 in which it provides detailed arguments on why "existing macroeconomic conditions demonstrate that increases in inflation are subjecting the Company to increased expenses." Aqua Exc. at 23 (citing Aqua Exc. at 26-29).[44] Moreover, Aqua argues that the ALJ's approach to reflect inflation by increasing the revenues the Company obtains under its negotiated water rate contracts is inconsistent and arbitrary given the effects of inflation on other aspects of the Company's revenue requirement that would entail a larger increase in revenue than what was recommended. *Id.*

In its Replies, the OCA disagrees with Aqua's position. The OCA notes that in its calculation, the 2023 inflation factor was only applied to January 2023, February 2023, and March 2023, because those three months are within the FPFTY ending March 31, 2023. The OCA, therefore, asserts that it reflected the contract rates at the end of the FPFTY, just as the Company has calculated its estimated revenues, customers served, operating expenses, and rate base as of March 31, 2023. OCA R. Exc. at 11 (citing OCA R.B. at 67; OCA St. 4 SR at 9).

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[44] We shall address Aqua Exception No. 7 separately, in Section VIII.J of this Opinion and Order, *infra*.

The OCA also disagrees with Aqua's argument that it would be inconsistent for the Commission to use higher inflation rates to calculate higher revenues if the impact of higher inflation rates on the Company's expenses is not recognized. OCA R. Exc. at 11 (citing Aqua Exc. at 23). According to the OCA, Aqua's general inflation adjustment was properly rejected because it was speculative and the Company did not provide specific evidence demonstrating that it would actually experience cost increases in those areas. Further, the OCA contends that the ALJ properly accepted the OCA's special contract revenue adjustment because the terms of the contract were specific about the adjustments that would occur in the FPFTY. *Id.* (citing R.D. at 52, 70-71).

Finally, the OCA acknowledged that the ALJ did not include adjustments for the Rider DRS contracts that she recommended should be charged full tariff rates. R.D. at 53. The OCA asserts that, to the extent the Commission does not adopt the ALJ's recommendation to move Chemung, Horsham, New Wilmington and Sharpsville from discounted contract rates to full tariff rates, special contract revenues for those contracts should be adjusted upward to reflect the escalation provisions (*i.e.*, the ALJ's recommended adjustment of $181,350 should be increased accordingly). OCA R. Exc. at 11-12 (citing R.D. at 53).

4. Disposition

Upon our review, we disagree with the ALJ's reliance on the escalation rate calculation utilized by the OCA in its proposed adjustment to special contract revenue. In support of her recommendation, the ALJ asserted that the OCA's adjustment to special contract revenue, which is based on an escalation rate calculation that uses the average of the US OMB's and Federal Reserve's forecasted inflation rates for 2021, 2022, and 2023, has "an apparent reliability and degree of impartiality because they are determined by government agencies." R.D. at 53. Although we agree that the sources for the OCA's adjustment values are reliable and fair, we are of the view that the Company provided a sufficient basis for justifying the reliability of the escalation provisions in the contracts.

As noted by Aqua, the escalation provisions in the relevant contracts specify how the inflation rate is to be calculated for annual escalation, and the OCA's recommendation would effectively substitute the agreed-upon escalation rate with a different rate. We find Aqua's argument here persuasive. Indeed, as noted by the Company, substituting the contractual escalation rate at this juncture would ultimately undermine the good-faith efforts of the related parties to negotiate an agreed-upon escalation rate. To the extent that the OCA argues that Aqua's inflation calculation does not sufficiently depict what inflation levels will be in the FPFTY, we are of the opinion that the inflation rates in the Company's negotiated rate contracts are substantiated, reliable, and do not require or necessitate an adjustment.

Therefore, we shall grant Aqua Exception No. 4 and modify the Recommended Decision by removing the ALJ's recommended upward adjustment of $181,350 to the Company's revenues associated with negotiated water contracts.

E. Metered Residential Sale Adjustment

1. Positions of the Parties

The Company proposed an adjustment to water consumption related to the COVID-19 pandemic. In making this adjustment, Aqua asserted that it would not assume that consumption by class in the future will be similar to usage patterns during the pandemic (*i.e.*, the HTY). Rather, the Company contended that projected consumption by class will be similar to usage patterns in its prior base rate case, *i.e.*, the *Aqua 2018 Rate Case*. As such, it proposed an adjustment to residential, commercial, and public customer classes based on the average usage presented in the *pro forma* FPFTY used in the *Aqua 2018 Rate Case*. The adjustment reduced residential water usage, and sales revenue by $11.03 million, and increased Commercial and Public Authority water usage, and sales revenue by $10.96 million. Aqua's proposed total overall change in revenue under present rates using this adjustment results in a decrease in total water revenues of $64,639. Aqua M.B. at 53; Aqua St. 5 at 17.

The OCA accepted Aqua's adjustments for Commercial and Public Authority water sales revenues to reflect pre-pandemic water sales revenue. However, the OCA recommended an adjustment that reflected 75% of the Company's proposed reduction for residential customers. In support, the OCA emphasized that the Company's metered residential water sales in 2020 were 1,181,614,000 gallons higher than in 2019, a pre-pandemic period. With increased residential water usage in 2020, the OCA argued that it would be unreasonable for Aqua to reduce HTY metered residential water sales by such a significant quantity for the purpose of deriving sales levels for the FPFTY. The OCA submitted that many residential consumers will continue to work from home and spend more time in their houses. According to the OCA, its recommendation would increase residential water sales by $2.757 million. OCA M.B. at 24-25.

In opposing the OCA's proposed adjustment to residential metered water sales, the Company cited substantial downward trends in residential usage for the months of September 2021 and October 2021 when compared with the pandemic months of September 2020 and October 2020. Aqua also argued that it was inconsistent for the OCA to accept the Company's revenue adjustments for commercial and public customers, but not residential customers. Aqua M.B. at 53-54; Aqua R.B. at 20.

In response, the OCA contended that Aqua's presumption that none of the 6.4% year-over-year increase in residential metered water sales is likely to continue beyond 2020 and into the FPFTY does not seem realistic. OCA St. 1 at 37. Rather, the OCA asserted that the record evidence supports a finding that the pandemic is ongoing and residential water usage is not reasonably likely to return to pre-pandemic levels in the FPFTY. OCA R.B. at 10-11.

2. Recommended Decision

The ALJ accepted Aqua's reduction to revenues to reflect removing the impact of COVID-19 on metered customer water sales. Initially, the ALJ found that the OCA's proposed acceptance of this adjustment for commercial and public customers, but not for residential customers, was inconsistent. Citing the testimony of Aqua's witness, Ms. Constance E. Heppenstall, the ALJ reasoned that if individuals are staying home and using more water than pre-pandemic, it should follow that usage for commercial and public classes should also be lower than pre-pandemic levels. R.D. at 54 (citing Aqua St. 5-R at 18).

Next, the ALJ determined that Aqua's position that usage trends support its proposed adjustment to water consumption due to the COVID-19 pandemic is reasonable and that the projection of a return of consumption toward pre-pandemic levels is credible. Additionally, the ALJ stated that the Company's approach to treat trends on the residential class consistently with trends in the commercial and public classes for the purposes of projections for the FPFTY is reasonable and supported by the record. R.D. at 54-55 (citing Aqua St. 5-R at 19).

3. OCA Exception No. 1 and Replies

In its Exception No. 1, the OCA argues that the ALJ erred in adopting Aqua's residential metered water sales when the pandemic continues to keep people using more water at home. In support, the OCA reiterates that the Company's residential metered water sales in 2020 were over one billion gallons higher than the pre-pandemic level in 2019. Given this significant increase, the OCA contends that it is unlikely that residential usage will decrease as quickly as Aqua predicts, such that usage would be back to "normal" for the purpose of deriving sales levels for the FPFTY. OCA Exc. at 1 (citing OCA St. 1 at 36).

Responding to the ALJ's finding that the OCA's adjustment to residential metered water sales is inconsistent with the acceptance of Aqua's prediction for commercial and industrial sales, the OCA submits that its recommendation reflects the unpredictability surrounding how and when the pandemic will come to an end. According to the OCA, recent data about residential water usage indicates that it is still up from pre-pandemic levels by as much as 9.1%. OCA Exc. at 1 (citing OCA St. 1-SR at 27-28).

The OCA adds that although commercial and industrial institutions are slowly re-opening, many workers are still spending more time at home. The OCA proffers that its recommended increase to residential revenues of $2.757 million addresses this slow return to pre-pandemic levels by reflecting 75% of Aqua's proposed reduction to residential revenues, in order to account for the decrease to residential water usage, but recognizing that it is not likely to return to pre-pandemic levels in the FPFTY. OCA Exc. at 2 (citing OCA St. 1, Exh. LA-2, Sch. C-6).

The OCA argues that its projections are more consistent with the data which recognizes a gradual return to consumption more closely aligning to pre-pandemic levels, while Aqua's assumptions assert, without basis, an immediate return. Based on its proposed revenue adjustment, the OCA recommends: (1) a related negative adjustment of $66,787 to the Company's claimed Chemicals Expense for water operations; (2) a negative adjustment to Purchased Power expense of $96,312; and (3) an adjustment to CWC to reflect this recommended revenue adjustment and based on the OCA's other expense adjustments. OCA Exc. at 2 (citing OCA M.B. at 22 and 30; OCA Table II (Water); and OCA Table II (Wastewater)).

In its reply, Aqua contends that the ALJ correctly accepted the Company's adjustments to water consumption for residential, commercial, and public customers associated with the pandemic and properly rejected the OCA's proposal that only 75% of the residential sales adjustment be applied. Aqua R. Exc. at 2.

In support, the Company emphasizes the ALJ's finding that the OCA's arguments are inconsistent because the OCA accepts the commercial and public customer adjustments but rejects the residential customer adjustments. Additionally, Aqua reiterates its contention that it presented credible evidence demonstrating the movement of usage for all classes toward pre-pandemic levels and requests denial of OCA Exception No. 1. Aqua R. Exc. at 2 (citing Aqua St. 5-R at 18-19).

4. Disposition

Upon review of the evidentiary record, pleadings, and arguments related thereto, we find that Aqua has demonstrated the reasonableness of its proposed adjustments to water consumption due to the COVID-19 pandemic.

The OCA emphasizes that Aqua reported metered residential water sales for 2020 of 19.552 billion gallons versus 18.370 billion gallons in 2019, a pre-pandemic period. The reported increase in residential water sales for this overall period between 2019 and 2020 was approximately 6.4%. OCA St. 1 at 37. Additionally, the OCA cites a specific percentage increase in residential water usage between October 2019 and October 2021 of 9.1%. OCA R.B. at 11; OCA St. 1-SR at 28.

In response, Aqua asserts that the specific increase in residential usage between October 2019 and October 2020 was accompanied by a decrease in residential usage between October 2020 and October 2021 – periods within the pandemic – of 5.6%. Additionally, the Company cites to a decrease in residential usage in the pandemic periods of September 2020 and September 2021 of 4.1%. The Company also showed increases in both commercial and public usage during these periods. Aqua shows the trends of usage within the pandemic periods in the following, which is reproduced in Table 2, below:

	Oct-20	Oct-21	Change	Percentage Change
Residential	1,636,326	1,545,471	(90,855)	-5.6%
Commercial	805,189	877,755	72,566	9.0%
Public	43,714	58,915	15,201	34.8%
	2,485,230	2,482,141	(3,089)	-0.1%

	Sep-20	Sep-21	Change	Percentage Change
Residential	1,706,364	1,636,859	(69,505)	-4.1%
Commercial	870,301	935,491	65,190	7.5%
Public	54,027	59,981	5,954	11.0%
	2,630,691	2,632,331	1,639	0.1%

Table 2: Aqua trends of usage within the pandemic periods

Aqua M.B. at 54; Aqua St. 5-R at 19.

We note that it would have been helpful to have had additional data comparing pandemic periods incorporating a comparison of more recent time periods (*i.e.*, showing trends in usage following recent COVID-19 variant surges). However, the Parties were limited to the presentation of evidence as of the evidentiary hearing and prior to the close of the record and that data appears to represent the most recent available information at the time. Under the circumstances, we find that the Company has submitted sufficient evidence to show a trend of declining residential usage which, when extrapolated over the FPFTY period, supports its proposal that residential usage will likely decline to the pre-pandemic period. Additionally, Aqua provides sufficient support to show a concomitant increase in commercial and public water usage.

Although the OCA correctly indicates that there was a large increase in overall residential water usage when comparing a pre-pandemic and a pandemic period, we find that the more helpful barometer is the trend of usage data within the pandemic periods as asserted by the Company. Moreover, it is unclear what data supports the OCA's calculation of including only 75% of Aqua's proposed reduction to residential revenues thereby resulting in an increase to residential revenues of $2.757 million. As to this proposed adjustment, the OCA states that it acknowledges a declining residential water usage but that it will not likely decline to the pre-pandemic level and that its proposal is more realistic than the Company's.

We recognize that the OCA does not bear the burden of proof in this proceeding.[45] However, there must be some evidence or analysis tending to show the reasonableness of the OCA's adjustment. In this regard, there is no apparent evidentiary support for a finding that residential usage will essentially remain high enough to result in a 25% increase in residential water sales when compared with a pre-pandemic period. Moreover, the OCA's proposed acceptance of the Company's adjustment for commercial and public customers, but not for residential customers, shows an inconsistency in the OCA's overall proposal. If individuals are staying home and using more water than prior to the pandemic, it would be reasonable to surmise that usage for commercial and public

[45] As the Commonwealth Court has explained: "While it is axiomatic that a utility has the burden of proving the justness and reasonableness of its proposed rates, it cannot be called upon to account for every action absent prior notice that such action is to be challenged." *See Allegheny Center Assocs. v. Pa. PUC,* 570 A.2d 149, 153 (Pa. Cmwlth. 1990) (*citing Central Maine Power Co. v. Public Utilities Commission*, 405 A.2d 153, 185 (Me. 1979)). Therefore, while the statutory burden of proof does not shift from the public utility in a general rate proceeding, a party proposing an adjustment to a ratemaking claim bears the burden of presenting some evidence or analysis, during the reception of evidence in the proceeding, tending to demonstrate the reasonableness of the adjustment. *See Id.*; *see*, *e.g.*, *Pa. PUC v. PECO,* Docket No. R-891364 *et al.*, 1990 Pa. PUC Lexis 155 (Order entered May 16, 1990); *see also Pa. PUC v. Breezewood Telephone Company*, Docket No. 901666, 74 Pa. P.U.C. 431 (Order entered February 15, 1991).

classes should also be lower than pre-pandemic levels. However, the available overall data shows that the Company is experiencing between a 4 to 5% decrease in residential usage and increases in both commercial and public usage. *See* Aqua St. 5-R at 19.

Accordingly, we shall deny OCA Exception No. 1 and thereby decline to make the OCA's requested adjustments to both residential water revenue and the expense categories that would have been impacted by its proposal.

F. Third Party Sales

1. Positions of the Parties

Aqua has eight third-party sales customers, from which it derives revenue at present rates of $1,095,381. The Company proposed to increase rates for all of its third-party customers except for its Southdown Homes and East Brandywine customers. Aqua R.B. at 18; I&E M.B. at 29. I&E recommended that the usage rate for Southdown Homes be increased from $0.749 per hundred gallons to $0.9535 per hundred gallons, which would result in an increase of $0.2045 per hundred gallons, or approximately 27.3%. I&E M.B. at 29. In its rebuttal testimony, Aqua revised its proposed revenue for Southdown Homes and provided a proof of revenue that shows Southdown Homes paying a usage rate of $1.35 per hundred gallons. I&E accepted this proposed usage rate. I&E M.B at 30; Aqua R.B. at 18; Aqua Exh. 5R-B, Sch. WW-5 at 17.

I&E also recommended an increase to the customer charge for the Company's East Brandywine customers from $351.00 per month to $446.75 per month. This equates to an increase of $95.75 per month, or approximately 27.3%. I&E based this recommendation on the average percentage increase for the Company's third-party customers. According to I&E, this percentage increase is reasonable given the higher percentage increase being proposed by Aqua for other third-party customers and the higher percentage increases proposed by Aqua for other wastewater customers. I&E further recommended that this flat rate should be increased and applied to the Company's revenues independent of any base rate increase granted by the Commission. I&E M.B. at 29, 30; I&E R.B. at 23.

Aqua found no reason to increase its East Brandywine rates. Therefore, Aqua opposed I&E's proposal to increase the customer charge for East Brandywine. Accordingly, Aqua submitted that its claimed revenues should not be modified to reflect I&E's recommendation. Aqua R.B. at 18-19.

2. Recommended Decision

The ALJ observed that Aqua did not offer any explanation as to why it was appropriate to retain the current rates for its East Brandywine customers when the Company: (1) originally proposed an increase to the rates for all of its third-party customers except for Southdown Homes and East Brandywine; and (2) subsequently accepted I&E's proposed increase for the Company's Southdown Homes customers. In contrast, the ALJ found that I&E's proposal would treat the Company's third-party customers consistently. As such, the ALJ found I&E's proposal to be more appropriate and recommended that it be adopted. The ALJ added that this is a rate design issue that does not require an adjustment to the Company's revenue requirement under present or proposed rates. R.D. at 56.

3. Disposition

No Party filed Exceptions on this issue with regard to the ALJ's recommendation. Finding the ALJ's recommendation to be based soundly on record evidence and reasonable, we shall adopt it. Accordingly, we shall adopt the ALJ's recommendation that approves I&E's proposal to increase the East Brandywine customer charge by $95.75 per month, or from $351.00 per month to $446.75 per month.

VIII. Expenses

A. Rate Case Expense

1. Positions of the Parties

Aqua provided that its rate case expense is $2,200,000, of which 91.51% is allocated to water cost of service and 8.49% is allocated to the wastewater cost of service based on the ratio of customers served to total customers. Aqua M.B. at 77 (citing Aqua St. 3 at 3). Aqua proposed to normalize the cost of the rate case expense over a thirty-six month period, which is the anticipated interval between this rate case and the Company's next base rate case. Aqua St. 3 at 3.

I&E recommended the rate case expense be normalized over thirty-six months. I&E M.B. at 31, 32.

The OCA recommended a reduction of $124,932 to the rate case expense by removing $59,932 not incurred from the "Other Consultants" costs and removing the $65,000 that Aqua has requested for "miscellaneous" costs. The OCA argued that the rate case expense should be normalized for thirty-nine months based on the actual historic frequency of Aqua's filings. OCA M.B. at 45.

2. Recommended Decision

The ALJ found Aqua's $2.2 million rate case expense to be reasonable. The ALJ opined that Aqua provided sufficient justification for including forecasted expenses for consultants. Additionally, the ALJ determined that Aqua's 36-month normalization period was reasonable. The ALJ stated that it was reasonable to exclude the "anomalous rate stay-out that was agreed to as part of a complex settlement negotiation" and rejected the OCA's longer normalization period of 3.3 years. R.D. at 57-58.

3. OCA Exception No. 6 and Replies

In its Exception No. 6, the OCA provides that the ALJ accepted Aqua's proposed thirty-six-month normalization period for rate case expense because the ALJ believed that to accept the OCA's proposed thirty-nine-month adjustment, which included the seven-year gap between Aqua's 2011 and 2018 rates, would discourage the negotiation of settlement stay-outs in the future. OCA Exc. at 7 (citing R.D. at 57-58). Additionally, the OCA notes the ALJ's statement that the reason Aqua did not file a rate case between 2011 and 2018 is that during that time Aqua was "constrained" by the stay-out it agreed to in the 2011 rate case. OCA Exc. at 7 (citing R.D. at 58). The OCA argues that Aqua was not "constrained" from filing a rate case between 2011 and 2018. Rather, the OCA continues, the stay-out negotiated in the 2011 settlement was for a term of only two years. OCA Exc. at 8 (citing *Pa. PUC v. Aqua Pa., Inc.*, Docket No. R-2011-2267958 (Order entered June 7, 2012) (*2011 Settlement*) at 18). According to the OCA, Aqua was free to file a rate case after the two-year time frame but chose not to do so for its own reasons. The OCA contends that including the time period between 2011 and 2018 in calculating the appropriate normalization period is reasonable. OCA Exc. at 8.

In its reply to the OCA Exception No. 6, Aqua avers that the OCA has misread the Recommended Decision. Aqua provides that it did not argue that it was "constrained" from making a base rate filing. Aqua explains that the "OCA's calculated average is distorted by the time period between Aqua's 2011 and 2018 rate case, based upon a circumstance specific to the settlement of the 2011 rate case that will not occur in the future." Aqua R. Exc. at 5 (citing Aqua M.B. at 79; Aqua St. 3-R at 9). Aqua provides that the circumstance was the initial adoption of the tax repairs election. Aqua R. Exc. at 5, n.2. Aqua avers that this distortion is why the Commission has noted that the normalization period for rate case filings may require consideration of future circumstances. Aqua R. Exc. at 5-6 (citing Aqua M.B. at 9). According to Aqua, this is consistent with prior precedent. Aqua R. Exc. at 6 (citing *Emporium Water Company*, Docket No. R-2014-2402324 (Order entered Jan. 18, 2015) at 48-49; *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-2012-2290597 (Order entered December 28, 2012) (*2012 PPL Order*); R.D. at 57; Aqua M.B. at 77-80; Aqua R.B. at 31-32).

I&E did not offer a reply to the OCA Exception No. 6 beyond stating that it agreed with the Company's recommendation of a thirty-six month normalization period. I&E R. Exc. at 14 (citing R.D. at 57-58).

4. Disposition

Aqua agreed to a two-year stay-out period in the *2011 Settlement* as follows:

> 9.a. The Company's agreement to a two-year stay-out from the filing date of this rate increase request, subject to the limited exceptions set forth in Paragraph No. 7.c., assures that, if [Aqua's] next general base rate water case were filed at the earliest permitted date and were fully litigated, the Settlement Rates would remain in effect for at least 26 months.

2011 Settlement at 18.

The OCA calculated the thirty-nine month normalization period by including the 2011 to 2018 gap in rate case filings. The ALJ rejected the OCA's thirty-nine month normalization period based on the *2011 Settlement* and the associated stay-out period in that Settlement. Aqua provides that the stay-out period was not the cause of the time lapse between Aqua's 2011 and 2018 base rate case filings, rather it was caused by the initial adoption of the tax repairs election. Aqua R. Exc. at 5, n.2.

While the OCA is correct that a two-year stay-out would not have "constrained" Aqua from filing a base rate case two years after the *2011 Settlement* and before the 2018 rate case filing, we do not recommend a thirty-nine month normalization period.

Aqua provided that the lapse between base rate case filings such as that between the 2011 and 2018 filings is not related to a stay-out or likely to recur as follows:

> The Company was able to avoid filing a rate case for an extended period after the 2011 rate case due to a provision in that settlement regarding the use of the tax repair deduction for income tax purposes. That situation will not recur in the future.

Aqua St. 3-R at 9.

We find Aqua's thirty-six month normalization period reasonable, and we accept the ALJ's recommendation of the thirty-six month normalization period. However, we will modify the Recommended Decision to remove the potentially confusing language in the paragraph on pages 57 – 58 of the Recommended Decision:

> In this case it is reasonable to exclude an anomalous rate stay-out that was agreed to as part of a complex settlement negotiation. The settlement stay-out does not generally reflect the Company's rate filing interval. This settlement

> term constrained Aqua's ability to file a rate case when it otherwise might have chosen to do so. To include the negotiated stay-out term in setting the normalization period for rate case expense might chill negotiations in future utility rate proceedings.

R.D. at 57-58.

Accordingly, the OCA's Exception No. 6 is granted, in part, and denied, in part.

B. General Liability Insurance Expense

1. Positions of the Parties

Aqua proposed a claim for general liability insurance based on a five-year average year-over-year increase of 5.97%. Aqua revised its claim based on opposition from I&E and the OCA. I&E proposed a "year-over-year three-year average" of 4.38%. I&E argued that the three-year average considers "more recent experience" and was consistent with the Company's method for calculating other categories of expenses (*i.e.*, uncollectibles expense and legal expense). Aqua M.B. at 75 (citing I&E St. 1 at 15-16). Aqua noted that the OCA's witness, Mr. Ralph C. Smith, accepted the Company's claimed FTY insurance expense but applied a 4.38% increase to the FTY to calculate his recommended FPFTY amount. Aqua M.B. at 75 (citing OCA St. 1 at 53-54). Aqua updated its claim for general liability insurance based on actual information that became available after the case had been filed. Aqua applied the three-year average increase of 4.38% to updated actual amounts accrued for Fiscal Year (FY) 2022. Aqua M.B. at 75 (citing Aqua St. 4-R at 6-7).

I&E and the OCA continued to disagree with Aqua's proposed claim. I&E "questioned the reliability of the amounts stated." Aqua M.B. at 77 (citing I&E St. 1-SR at 15). I&E's witness, Ms. Christine Wilson, explained that Aqua's revised claims for all the wastewater revenue requirements decreased from direct testimony to rebuttal testimony with no explanation for that directional change. I&E stated that Aqua did not provide documentation for the recent 2022 accruals to support the proposed changes in general liability expense. R.D. at 59. The OCA argued that Aqua's calculation "inconsistently mixes calculation elements." Aqua M.B. at 77 (citing OCA St. 1-SR at 40).

2. Recommended Decision

The ALJ recommended that the Commission adopt I&E's adjustments to the Company's general liability insurance expense. The ALJ reasoned that Aqua failed to provide adequate documentation in support of its treatment of insurance expense, nor is the mixing of calculation elements justified for the purposes of projecting expense increases. The ALJ recommended that Aqua's claim for insurance expense should be decreased by $340,945 for water and increased by $29,967 for wastewater. The ALJ explained that the wastewater adjustments are comprised of increases for Wastewater Base, Limerick, East Bradford, and Cheltenham of $18,640, $3,533, $789, and $6,299, respectively, and a decrease for New Garden of $676.[46] R.D. at 59.

3. Aqua Exception No. 5 and Replies

In its Exception No. 5, Aqua contends that it fully explained how it calculated its projection of general liability insurance expense for the FPFTY. Aqua Exc.

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[46] We note that in her explanation, the ALJ inadvertently omitted an increase of $1,382 for East Norriton Wastewater. See I&E St. 1-SR at 16.

at 24 (citing Aqua M.B. at 74-75). Aqua explains that it updated its insurance claim to reflect actual general liability expense information for the Year 2022 that became available after the case had been filed. Aqua Exc. at 24 (citing Aqua M.B. at 75). Aqua further submits that it then used I&E's proposed three-year average percentage increase to this expense to adjust the final quarter of the FPFTY. Aqua Exc. at 24 (citing Aqua M.B. at 75-76; Aqua St. 4-R at 6-7).

Aqua provides that although the ALJ concluded that the Company improperly mixed calculation elements, there is nothing unusual or improper in updating the claim to reflect known, actual information for FY 2022, or in developing the FPFTY claim using three quarters of that actual data and one quarter of projected data using the same adjustment factor (4.38%) proposed by both the OCA and I&E. According to Aqua, there is no evidence of record to support I&E's concerns regarding the reliability of this information. Aqua Exc. at 24 (citing Aqua R.B. at 30).

Aqua avers that the Recommended Decision inconsistently accepts I&E's calculation as credible but rejects Aqua's calculation which uses the same method updated with the most recent data available. Aqua Exc. at 25.

In its reply to Aqua Exception No. 5, I&E notes that after reviewing the record evidence presented by all parties, the ALJ correctly concluded that Aqua failed to provide adequate documentation in support of its treatment of insurance expense and the mixing of calculation elements is not justified for the purposes of projecting expense increases. I&E R. Exc. at 8-9 (citing R.D. at 59).

4. Disposition

I&E notes that the Company has recorded its calendar year 2022 insurance expense for accounting purposes, similarly updating the claim for ratemaking purposes, and on a consolidated basis the accrual produces a year-over-year increase of 8.49% between calendar year 2021 and 2022 based on premiums the Company will pay in 2022. I&E St. 1-SR at 14 (citing Aqua St. 4-R at 6). I&E explains that the Company has updated its entire FTY claim for insurance and the first nine months of the FPFTY (April 1, 2022 through December 31, 2022) based on the recently determined accruals. I&E explains further that the final three months of the FPFTY (January 1, 2023 through March 31, 2023) were inflated using a 4.38% increase to the FTY result. *Id.*

I&E provided the updated expense portion of the insurance claims, noting that the revised claims for all the wastewater revenue requirements have decreased from direct testimony to rebuttal testimony with no explanation for the directional change. I&E St. 1-SR at 15. We agree with I&E, that Aqua has not provided an explanation for these updated insurance claims and provided no documentation for the recent 2022 accruals to support the changes in rebuttal testimony.

Therefore, we shall deny Aqua's Exception No. 5, and adopt the ALJ's recommendation that Aqua's claim for insurance expense should be decreased by $340,945, or from $4,915,277 to $4,574,332 for water and increased by $29,967, or from $39,853 to $69,820 for wastewater. The wastewater adjustments are comprised of: (1) an increase for Wastewater Base of $18,640, or from $16,327 to $34,967; (2) an increase for Limerick of $3,533, or from $5,613 to $9,146; (3) an increase for East Bradford of $789, or from $1,232 to $2,021; (4) an increase for Cheltenham of $6,299, or from $9,814 to $16,113; (5) an increase for East Norriton of $1,382, or from $4,915 to $6,297; and (6) a decrease for New Garden of $676, or from $1,952 to $1,276. R.D. at 59; I&E St. 1-SR at 16. These adjustments are outlined in Table II-Adjustments in each of the groups of rate tables in the Commission Tables Calculating Allowed Revenue Increase, attached to this Opinion and Order.

C. Payroll

1. Positions of the Parties

Both I&E and the OCA proposed adjustments to Aqua's claim for payroll expense. I&E proposed a vacancy rate of 6.83%. The OCA proposed a vacancy rate of 2.88%, rather than the Company's 2.50%. Aqua opposed I&E's vacancy rate but accepted the OCA's 2.88% full time vacancy rate. Aqua M.B. at 66. Aqua's witness, Ms. Erin M. Feeney, explained that I&E's adjustment double counts the adjustment already built into the Company's claim as a part of the gross payroll amounts. Aqua M.B. at 66 (citing Aqua St. 2-R at 37; Aqua St. 2 at 11). Subsequently, I&E withdrew its adjustment for payroll expense. Aqua M.B. at 66 (citing I&E St. 1-SR at 25).

The OCA calculated its vacancy rate of 2.88% based on information provided in response to I&E-RE-22-D. According to the OCA, the 2.88% vacancy rate is based on the difference between actual regular hours and authorized regular hours during the HTY, and more accurately reflects Aqua's expense. OCA M.B. at 33-34 (citing OCA St. 1 at 41-42). The OCA proposed an adjustment decreasing payroll expense by $119,358 for the Company's water operations and $6,855 for wastewater operations. The OCA provided that in aggregate, this calculation decreases payroll expense by $126,213. OCA M.B. at 34 (citing OCA St. 1 at 44-45; OCA Exh. LA-2, Sch. C-11 at 2).

The OCA proposed an additional adjustment to payroll expense by reducing the number of seasonal positions included in the Company's claim to reflect the level of seasonal employees as of June 30, 2021. Aqua M.B. at 67 (citing OCA St. 1 at 43-44).

2. Recommended Decision

The ALJ recommended that the Company's payroll expense as updated with the OCA's 2.88% vacancy rate should be accepted. R.D. at 60 (citing Aqua Exh. 1-A(a) and 1-B(b) through 1-G(g)). The ALJ reasoned that Aqua had supported its projection for seasonal positions with the testimony of Ms. Feeney. Specifically, the ALJ stated that the 2020 and 2021 number of seasonal positions filled were impacted by the COVID-19 pandemic and should be considered outliers. The ALJ noted that Aqua anticipates filling all thirty-three seasonal positions during the FPFTY. R.D. at 60 (citing Aqua St. 2-R at 39).

3. OCA Exception No. 5 and Replies

In its Exception No. 5, the OCA disagrees with the ALJ's finding that Aqua has adequately supported its claim for thirty-three seasonal employees. The OCA submits that while Aqua may believe that it will fill all thirty-three of its budgeted-for seasonal positions in the FPFTY, the Company has failed to provide evidence that this is likely. According to the OCA, the record indicates that Aqua has not consistently filled all of its seasonal positions even before the COVID-19 pandemic began. OCA Exc. at 6-7 (citing OCA M.B. at 34-35). The OCA provides that in 2019, Aqua filled only thirty-one of the budgeted thirty-three positions. During the pandemic, the OCA continues, Aqua filled only eleven out of thirty-three budgeted positions. OCA Exc. at 7 (citing OCA St. 1SR at 32-33). The OCA avers that it is not reasonable to assume that Aqua's hiring will be more robust than before the pandemic. The OCA recommends an adjustment of $286,373 to remove payroll expense for twenty-two of the authorized seasonal positions. OCA Exc. at 7.

In its reply to OCA Exception No. 5, Aqua argues that the ALJ correctly reasons that the payroll expense claim, including the seasonal positions, is "based upon anticipated normal operating conditions" during the FPFTY. Aqua R. Exc. at 5 (citing R.D. at 61). Aqua contends that the seasonal employee counts for 2020 and 2019 were impacted by the COVID-19 pandemic and are not reflective of normal operating conditions. Aqua R. Exc. at 5.

4. Disposition

The seasonal employment period runs from mid-May to mid-September. I&E Exh. 1, Sch. 5 at 2. The OCA contends that the seasonal employee count should reflect the level as of June 30, 2021 when eleven positions were filled. We disagree with the OCA's recommendation. The record does not clearly indicate that the number of seasonal employee positions as of June 30, 2021 reflects the total number employed through the seasonal employment period for 2021, or going forward. The Company filled thirty-one seasonal positions in 2019. The Company has noted that it expects to return to more normal operations. We agree with the ALJ that the Company's assertion that it will be able to fill thirty-three seasonal positions going forward in the FPFTY is reasonable. The OCA Exception No. 5 is denied.

D. Stock-based Incentive Compensation

1. Positions of the Parties

Aqua has included expenses related to its stock-based incentive compensation program. Aqua maintained that this is an important part of its overall compensation program. R.D. at 61. Aqua averred that it is entitled to recover, in rates, all expenses reasonably necessary to provide service to customers. According to Aqua, the OCA has not claimed that the total stock reward expenses were unreasonable, imprudent, or excessive. Aqua noted that the OCA objected to the expenses on the basis that shareholders benefit from increases in stock prices, without consideration for the customer benefits derived from achievement of the customer performance metrics applied to stock rewards. Aqua M.B. at 69.

Aqua stated that the Commission has established a bright line test for incentive compensation expense. According to Aqua, if the incentive compensation programs of the utility are reasonable and provide a benefit to ratepayers, then they may be recovered in their entirety. Aqua M.B. at 69 (citing *2012 PPL Order* at 26). Aqua noted that the Commission recently applied this standard in approving the recovery of stock-based incentive compensation in *Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058 (Order entered October 25, 2018) (*UGI Electric*).

Aqua averred that it demonstrated that its stock reward plans include both financial and operating metrics and goals. Aqua provided that it further demonstrated that its incentive compensation package is reasonable, prudently incurred and not excessive in amount. Aqua's witness, Mr. William C. Packer, explained:

> [A] key component of the incentive compensation plan is employee objectives that provide benefits to customers. Many of the employee objectives focus on cost containment, quality service, productivity enhancements and compliance initiatives to ensure reasonable cost and high-quality service to our customers.

Aqua M.B. at 70 (citing Aqua St. 1-R at 17-18).

I&E did not object to the Company's proposed incentive compensation plan expense.

The OCA acknowledged that where an incentive compensation plan is reasonable, prudently incurred, not excessive, and there is a benefit to ratepayers, a company may recover the expense of that program. The OCA noted that the Commission has approved recovery for incentive compensation programs when they are focused on improving operational effectiveness. OCA M.B. at 36 (citing *2012 PPL Order*).

The OCA averred that Aqua's stock-based compensation program provides Aqua and Essential Utilities executives with compensation based on the performance of the Company's or parent company's stock price. According to the OCA, absent a clear tie to ratepayer benefit or operational effectiveness, it is unreasonable to burden ratepayers with the costs of the stock compensation program. OCA M.B. at 37.

2. Recommended Decision

The ALJ accepted Aqua's position that the stock-based compensation program benefits ratepayers. The ALJ explained that the Company described how the purpose of the plan is to tie compensation to employees accomplishing the Company's main objectives, which benefits consumers. R.D. at 62 (citing Aqua St. 1-R at 15-16). The ALJ further explained that Aqua stated that compensation from the program is both "competitive" and "appropriate." The ALJ noted that the Company has been using the program since 1999,[47] and thus claims that the program is a key element of its overall payment package in attracting and keeping a skilled workforce. R.D. at 62 (citing Aqua St. 1-R at 17). The ALJ reasoned that the OCA's argument that the program also benefits stockholders is not sufficient to demonstrate that the program is unreasonable or excessive. R.D. at 63.

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[47] We note that the Company states that the Incentive Compensation Plan was started in 1990. Aqua St. 1-R at 16.

3. OCA Exception No. 4 and Replies

In its Exception No. 4, the OCA disagrees with the ALJ's findings regarding Aqua's stock-based incentive compensation program. The OCA recommends an adjustment of $846,493 to remove these costs. OCA Exc. at 4-5 (citing OCA M.B. at 36-39; OCA Table II (Water); Table II (Wastewater)). According to the OCA, the ALJ noted that since the purpose of the plan is to tie compensation to employees accomplishing the Company's objectives, the program must ultimately benefit consumers. OCA Exc. at 5 (citing R.D. at 62). The OCA contends that Aqua has failed to demonstrate that the key component of the program is to establish employee eligibility based on performance duties and metrics that are "*directly related to the provision of service*." OCA Exc. at 5 (citing *Pa. PUC v. Pennsylvania American Water Co.*, 2021 Pa. PUC LEXIS 55 (*PAWC 2021*) at *59-60).

The OCA provides that although, in theory, a payment program which benefits stockholders might also benefit consumers, in this case, the payment program has no clear relationship to ratepayer benefits or operational effectiveness. OCA Exc. at 5 (citing OCA St. 1 at 48). The OCA avers that the stock-based incentive compensation program appears to have the primary purpose of benefitting executives and high-level managers. However, the OCA argues that no evidence has been provided to show the benefits of the payment program to ratepayers. OCA Exc. at 5 (citing OCA St. 1SR at 36).

The OCA highlights the ALJ's statement that Aqua has established that compensation from the program is both "competitive" and "appropriate." OCA Exc. at 5 (citing R.D. at 62). While this may be true, the OCA argues, it is irrelevant to whether the program is benefitting ratepayers and whether it should be funded by ratepayers. OCA Exc. at 5.

The OCA avers that Aqua's incentive compensation program is not reasonable or prudently incurred. In addition, the OCA insists that there is no evidence that it provides any benefit to ratepayers and, accordingly, Aqua should not be able to recover the plan expenses from ratepayers. The OCA remains of the opinion that its $846,493 adjustment to remove these costs for ratemaking should be adopted. OCA Exc. at 6 (citing OCA M.B. at 36-39; OCA Table II (Water) and (Wastewater)).

In its reply to the OCA Exception No. 5, Aqua avers that the incentive compensation has been paid each year since 1990, demonstrating that the plan is successful in encouraging the accomplishment of Aqua's key objectives and the ongoing control over operating costs. Aqua R. Exc. at 4 (citing Aqua St. 1-R at 16-17).

I&E did not offer a reply to OCA Exception No. 5.

4. Disposition

We find that Aqua has provided evidence linking the stock-based incentive compensation program with benefits to customers and improved operational efficiency. Aqua's witness Mr. Packer explained that with the implementation of the Incentive Compensation Plan in 1990, a portion of an employee's total cash compensation was placed "at risk" pending the achievement of key performance objectives. The employee's progress toward these performance objectives was used to determine the employee's resulting percentage of a target bonus. Aqua St. 1-R at 15.

Mr. Packer explained further the rationale of the Company's incentive compensation plan as follows:

> The purpose of the Plan is to tie employee compensation to the accomplishment of the Company's key operating objectives, thereby ensuring that the entire workforce is

> working toward the same end. Customers benefit from the participant's individual objectives being met, as improvements in performance are accomplished by controlling costs, improving efficiencies and enhancing customer service. As a result, the need for rate relief is mitigated.

Aqua St. 1-R at 15-16.

Mr. Packer stated that "[m]any of the employee objectives focus on cost containment, quality service, productivity enhancements and compliance initiatives to ensure reasonable cost and high-quality service to our customers." Aqua St. 1-R at 17-18. Mr. Packer provided that "[s]tock compensation is an equally important form of compensation at risk, promotes retention, and emphasizes an investment interest in the business at the employee level that promotes efforts to provide safe, adequate, and reliable utility service." Aqua St. 1-R at 19.

We agree with the ALJ that the stock-based compensation benefits ratepayers. We find that the stock-based compensation is linked to performance objectives that benefit consumers, including controlling costs and compliance initiatives. Accordingly, the OCA Exception No. 5 is denied.

E. Supplemental Executive Retirement Plan (SERP)

1. Positions of the Parties

Aqua explained that the SERP is a legacy retirement program for highly compensated individuals who did not qualify under the Company's former pension plan due to Internal Revenue Service (IRS) limitations. Aqua M.B. at 72 (citing Aqua St. 1-SR at 11-12). In April 2003, the Company closed both the pension plan and its SERP to employees hired after that date. Aqua averred that the SERP provides replacement retirement benefits for a limited number of past and present employees and their spouses who are not eligible for the Company's former pension plan. Aqua M.B. at 72 (footnote omitted).

The OCA provided that the Company's claim unreasonably imposes an expense for SERP for Essential Utilities and Aqua top executives on consumers when that expense is not affiliated with the provision of public utility service. The OCA noted that the SERP provides retirement benefits for select highly compensated executives that goes beyond what employees with qualified pension plans receive and beyond IRS limitations for qualified plans. The OCA explained that without the expense of SERP, the Company's executives would still receive retirement benefits available to any other Aqua employee. According to the OCA, an expense that exists for the purpose of providing additional compensation to executives that are already the highest paid in the Company is both excessive and unnecessary to the provision of water service.
OCA M.B. at 49 (citing *Pa. PUC v. Pennsylvania American Water Co*., 1993 Pa. PUC LEXIS 79 (*PAWC 1993*) at *121-123, 136-139 (holding that unnecessary expenditures that do not relate to the provision of utility service should not be borne by ratepayers)). The OCA argued that while the Company is free to provide these additional retirement benefits to its executives, it should do so at the expense of shareholders rather than ratepayers. The OCA recommended removing the requested FPFTY expenses of $695,612 for the water utility and $57,050 for the wastewater utility. OCA M.B. at 49 (citing OCA St. 1 at 62; OCA Exh. LA-2, Sch. C-18; Table II (Water); Table II (Wastewater Base)).

2. Recommended Decision

The ALJ noted that the SERP is not associated with retaining or recruiting executive talent. R.D. at 63. The ALJ provided that Aqua did not demonstrate that the SERP is connected to employee performance metrics that relate to the provision of utility service. The ALJ recommended the SERP expenses be excluded and that $695,612 for the water utility and $57,050 for the wastewater utility be removed from the requested FPFTY expenses. For wastewater, the ALJ recommended that the $57,050 adjustment be allocated to each rate zone based on the relative percentage of management fees assigned to each rate zone per Aqua Exhibits 1-B to 1-G at Sch. C-1. The ALJ recommendations are as follows:

> The wastewater adjustments are comprised of decreases for Wastewater Base, Limerick, East Bradford, Cheltenham, East Norriton, and New Garden of $23,373; $8,035; $1,763; $14,049; $7,036; and $2,794; respectively. These adjustments are reflected in each rate case under [Recommended Decision, Appendix] Table II, row "Supp. Exec. Retire Program." As noted in [Recommended Decision, Appendix] Table VI for each rate zone, the cash working capital resulting from this SERP adjustment is recommended to be assigned to the management fee expense account for each rate zone.

R.D. at 63-64.

3. Aqua Exception No. 6 and Replies

In its Exception No. 6, Aqua avers that the Recommended Decision improperly applies incentive compensation recovery criteria to a post-employment retirement benefit to reach an incorrect recommendation. Aqua explains that the SERP is a legacy retirement program, similar to the Company's pension plan but limited to certain senior level employees who did not qualify under the Company's former pension plan due to Internal Revenue Code limitations. Aqua Exc. at 25 (citing R.D. at 63). Aqua notes that the SERP provides replacement retirement benefits for the limited number of present and retired employees and their spouses who are not eligible for the Company's qualified pension plan. Aqua Exc. at 25.

Aqua maintains that eligibility for benefits each year under the SERP is not based upon performance criteria, but upon employment. When the program closed to new employees after April 2003, the pre-April 2003 employees continued to receive their promised benefits upon retirement. Aqua replaced the SERP and the pension plan with a defined contribution 401(k) program to control costs. Aqua Exc. at 26, n.15. Aqua notes that like the pension plan, the Company continues to incur costs under this legacy plan. Aqua expects the cost of the program to decline over time. Aqua Exc. at 25-26.

Aqua avers that as a post-employment benefit, recovery of the costs of the program in rates should not be measured by whether it serves as a current recruiting tool, or whether the recipient retirees have met an incentive target. Aqua Exc. at 26.

In its reply to Aqua Exc. No. 6, the OCA submits that the Company acknowledges that the SERP has no connection to the provision of utility service, to customer service, or to attracting and retaining new employees. OCA R. Exc. at 3 (citing OCA M.B. at 47-50; OCA R.B. at 23-24).

The OCA disagrees with Aqua's argument that the SERP should be included in rate recovery because excluding the program would "disincentivize utilities from changing or eliminating post-employment benefits, if the ongoing costs of a discontinued program may no longer be recoverable." OCA R. Exc. at 3 (citing Aqua Exc. at 26). The OCA contends that Aqua's argument has no basis in Commission precedent because it ignores that compensation programs wholly disconnected from utility service should never be funded, whether those programs are discontinued or current. OCA R. Exc. at 3 (citing OCA M.B. at 47-48; OCA R.B. at 23-24).

4. Disposition

We agree with the OCA, that not all costs incurred by Aqua are recoverable. While Aqua continues to incur costs from the SERP, Aqua's customers who receive no benefit from and have no ties to the SERP, should not be required to fund these costs. We agree with the ALJ's recommendation to remove the Company's FPFTY expenses of $695,612 for water and $57,050 for wastewater, in the manner outlined by the ALJ, *supra*. Accordingly, Aqua Exception No. 6 is denied.

F. Non-Rate Case Legal Expense

1. Positions of the Parties

Aqua proposed a three-year average of non-rate case legal expenses to reflect the costs incurred in a normal year, including the costs of union contract negotiations that occur on a two-year or more interval. Aqua M.B. at 80-81. Aqua's claim includes a request to recover $644,4475 in non-rate case legal expense. Aqua M.B. at 80.

The OCA recommended a reduction of $24,981 in Aqua's non-rate case legal expense to more accurately reflect the average amounts recorded by Aqua for the twelve month periods ending March 31, 2020 and March 31, 2021. OCA R.B. at 22 (citing OCA M.B. at 47). The OCA provided that its suggested two-year time frame excludes the 2019 year because the expense that year was unusual and is not representative of current or future levels of non-rate case legal expense. *Id.*

2. Recommended Decision

The ALJ reasoned that the use of a two-year average, as the OCA recommended, would fail to include expenses that occur on a two-year or more interval, such as union negotiations. The ALJ noted that according to Aqua, its proposal is consistent with its claim in prior rate cases and other expense categories that exhibit similar ebbs and flows as in this case. The ALJ found Aqua's claim based on a three-year average of non-rate case legal expenses to be reasonable. R.D. at 64-65 (citing Aqua St. 3-R at 10).

3. OCA Exception No. 3 and Replies

In its Exception No. 3, the OCA contends that the ALJ erred by accepting Aqua's claim for $644,475 for non-rate case legal expense. OCA Exc. at 3 (citing R.D. at 65). The OCA avers that this amount of non-rate case legal expense was derived from a three-year average of non-rate case legal expense. The OCA notes that it proposed averaging two years of non-rate case legal expense instead of three, to exclude the year ending March 31, 2019, in which Aqua had unusually high legal expenses. OCA Exc. at 3 (citing OCA M.B. at 47). The OCA avers that Aqua's non-rate case legal expense in the year ending March 31, 2019 was unusually high and it does not provide an accurate representation of what that expense will be in the future. OCA Exc. at 4 (citing OCA M.B. at 47). According to the OCA, Aqua's non-rate case legal expense has decreased in each of the two years following 2019. OCA Exc. at 4 (citing OCA St. 1 at 58). Additionally, the OCA contends that Aqua has failed to establish that any expenses from the 2019 year are recurring. The OCA argues that Aqua's non-rate case legal expense should be reduced by $24,981 to more closely reflect what the Company's expenses will be in the future. OCA Exc. at 4 (citing OCA M.B. at 47; OCA Exh. LA-2, Sch. C-17 at 2, Table II (Water)).

In its reply to the OCA Exception No. 3, Aqua provides that a three-year average for non-rate case legal expense accounts for the fluctuation of this expense that occurs in the normal course of business. In addition, the Company claims, that the two-year average proposed by the OCA may not capture regular cyclical legal expenses such as union contract negotiations. Aqua R. Exc. at 3 (citing Aqua M.B. at 81).

4. Disposition

We agree with the ALJ that a three-year average for non rate case legal expense is reasonable. In our view, a three-year average is more appropriate to include costs that a two-year average would not capture. Aqua's union contract negotiations are scheduled to occur during the FTY. Aqua St. 3-R at 10. As Aqua pointed out, the Company has used a three-year average for this expense in its prior rate case. Aqua M.B. at 81.[48] The OCA Exception No. 3 is denied.

G. Purchased Water Expense

1. Positions of the Parties

Aqua has included a claim for $4,135,311 for Purchased Water Expense during the FPFTY. Aqua M.B. at 81 (citing Aqua Exh. 1-A, Sch. C-7.1). The amount includes $297,839 of purchased water from Aqua Ohio. Aqua M.B. at 82 (citing Aqua Exh. 1-A, Sch. C-7.1.i, Line1).

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[48] We note that Aqua used a three-year average to calculate its Legal Expense Claim in the *Aqua 2018 Rate Case*. *Aqua 2018 Rate Case*, Aqua Exh. 1-A(a), Sched. C-9.1. <u>This claim was included within the Settlement approved by the Commission in the *Aqua 2018 Rate Case*.</u>

I&E proposed a decrease of $166,975, reflecting water purchases from Aqua Ohio at $0.3449 per hundred gallons. I&E St. 1-SR at 19 (citing I&E St. 1 at 19). I&E argued that the cost of purchased water (Aqua Ohio Struthers Division) should be the same as the rate Aqua Pennsylvania receives when it sells water to that same affiliate (Aqua Ohio Masury Division) for ratemaking purposes so that Pennsylvania customers are not harmed. According to I&E, the Ohio rate is not guaranteed full recovery when that tariff rate is being claimed by a Pennsylvania affiliate in a Pennsylvania rate filing. I&E M.B. at 34-35 (citing St. 1-SR at 20).

Aqua's witness, Ms. Feeney, explained that I&E's recommendation ignores the fact that Aqua's sales to the Masury Division and Aqua's purchases from the Struthers Division of Aqua Ohio are not comparable. R.D. at 66 (citing Aqua St. 2-R at 33). Aqua explained further that these sales and purchases take place in different geographic locations. Additionally, Aqua highlighted that the Masury and Struthers Divisions of Aqua Ohio are separate – each division has a separately determined cost of service, separate tariffs, and different rates. *Id.*

2. Recommended Decision

The ALJ recommended that I&E's proposed adjustment be rejected. The ALJ reasoned that there is no evidence that the purchase of water from Aqua Ohio Struthers Division at tariffed rates is imprudent or excessive. The ALJ noted that in considering the Masury contract, the Commission will determine whether the sale of water to Masury at discounted rates is appropriate. The ALJ stated that as the purchase of water from Aqua Ohio Struthers division is made pursuant to tariff rates that have been approved by the applicable authorities with jurisdiction to regulate those utility rates, Aqua's claimed purchased water expense should not be adjusted. The ALJ further reasoned this rate is unaffected by the rate to be charged by Aqua to the Masury Division, which Aqua based upon a contract rate established in relation to the cost of a competitive alternative available to the Masury Division. R.D. at 66.

3. Disposition

No Party filed Exceptions on this issue. Finding the ALJ's recommendation to be reasonable, we adopt it without further comment.

H. Dredging Expense

1. Positions of the Parties

Aqua proposed to change its dredging process and to accrue a reserve exclusively for dredging costs at a rate of $400,000 per year and charge actual costs against that reserve as they are incurred. Aqua M.B. at 85 (citing Aqua St. 3 at 5). Aqua proposed that the reserve be recorded as a regulatory liability. Aqua stated that this proposed adjustment would reduce dredging expense by approximately $300,000 over three years. Aqua would change its past practice of mobilizing and demobilizing equipment (with fixed costs of approximately $150,000 per occurrence) three times over a three-year span, to only one time over a three-year span. *Id.*

I&E recommended no adjustment to the claimed dollar amount, but recommended that Aqua's dredging expense be normalized and that the Company's proposed use of a reserve account and regulatory liability be rejected. I&E M.B. at 36 (citing I&E St. 1 at 21; I&E St. 1-SR at 21). I&E argued that dredging is a routine expense and should be normalized for ratemaking purposes. *Id.*

2. Recommended Decision

The ALJ recommended that the dredging expense be normalized and that the requested approval for deferred accounting treatment should be rejected. The ALJ reasoned that while the claimed expense may be substantial, it is not extraordinary, non-recurring, or within the scope of the type of items that the Commission has allowed as an exception to the general rule against retroactive recovery. R.D. at 67.

3. Disposition

No Party filed Exceptions on this issue. Finding the ALJ's recommendation to be reasonable, we adopt it without further comment.

I. Advertising

1. Positions of the Parties

Included in Aqua's claim for advertising expense is $75,000 for water operations and $7,500 for wastewater operations related to the advertising for the Company's proposed Universal Service Program (USP). Aqua M.B. at 86 (citing Aqua St. 2-R at 34-35; OCA Exh. LA-3, 17-18).

The OCA recommended that the Company only be permitted to recover $25,000 for water operations and $2,500 for wastewater operations for this category of advertising. Aqua M.B. at 86 (citing OCA St. 1 at 40). The OCA considered this a new expense, since it was not incurred in the HTY and FTY. The OCA proposed to normalize the FPFTY amounts claimed by Aqua for this expense over three years. Aqua M.B. at 86 (citing OCA St. 1 at 41).

Aqua provided that the program was not in effect in the HTY and will not be in effect during the FTY. Aqua proposed the new program to be in effect in the FPFTY and averred that to normalize this expense with prior years when the program did not exist is unfair. Aqua M.B. at 87.

2. Recommended Decision

The ALJ recommended that Aqua's claimed expense to advertise the proposed new USP should be accepted. The ALJ reasoned that the program is proposed to be in effect during the FPFTY and, therefore, Aqua's advertising expense reasonably projects the new amounts associated with ensuring customers are informed about the new program. R.D. at 69 (citing 66 Pa. C.S. § 1316).[49]

3. OCA Exception No. 2 and Replies

The OCA avers that normalizing this cost for customer outreach for the new USP over three years is consistent with an understanding that advertising priorities change over time. The OCA provides that normalization of a new expense being introduced for the first time in the FPFTY that may fluctuate in future rate cases is required under Commission precedent. OCA Exc. at 3 (citing *Pa. PUC v. Pennsylvania American Water Co*., Docket Nos. R-00038304, *et al.*, 2003 Pa. PUC LEXIS 498 (Recommended Decision issued December 2, 2003) (*PAWC 2003*) at *101-102, *adopted as modified*, Order entered January 29, 2004).

[49] *See* 66 Pa. C.S. § 1316 (permitting utilities to recover advertising expenses that "(4) Provides important information to the public regarding safety, rate changes, means of reducing usage or bills, load management or energy conservation" or "(5) Provides a direct benefit to ratepayers.").

The OCA argues that normalization would reduce the impact for rate payers, and that Aqua has failed to explain why doing so prevents it from accomplishing its goal of customer outreach. OCA Exc. at 3 (citing OCA M.B. at 32).

In its reply to the OCA Exception No. 2, Aqua contends that the ALJ correctly concluded that Aqua is permitted to recover the expense under 66 Pa. C.S. § 1316 and that to require Aqua to normalize an expense to be incurred in the FPFTY for a program to be implemented in the FPFTY is unfair. Aqua R. Exc. at 2-3 (citing R.D. at 68-69; Aqua M.B. at 86-87). Aqua avers that, as the ALJ noted, the OCA proposed increased outreach efforts for the proposed USP. Aqua R. Exc. at 3 (citing R.D. at 69). Aqua argues that the OCA offered no evidence to indicate Aqua's existing level of advertising expense, exclusive of the new CAP spending, is excessive. Aqua contends that the OCA is relying on an inapposite case that dealt with the specific variability of uncollectibles expense and not a new expense associated with a new program. Aqua R. Exc. at 3 (citing Aqua R.B. at 35; *PAWC 2003* at *101-102).

4. Disposition

We find the advertising expense for the proposed USP to be reasonable. We agree with the ALJ that to normalize the expense over three years is not fair. We do not agree with the OCA's argument that Commission precedent requires the normalization. The *PAWC 2003* citation is related to an expense that varied over three years, not an expense for a new program occurring for the first time in the FPFTY. Accordingly, the OCA Exception No. 2 is denied.

J. General Price Level Adjustment

1. Positions of the Parties

Aqua provides that its "General Price Level Adjustment" reflects the anticipated effect of inflation on operating expenses that were not specifically adjusted. Aqua M.B. at 59 (citing Aqua St. 3 at 2, Aqua Exhs. 1-A; 1-B through 1-G; Sch. C-4.1). Aqua explains that it derived its inflation factors based on the quarterly Consumer Price Index (CPI) percentage change from the same quarter in the prior year set forth in the October 10, 2020, Blue Chip Economic Indicators. Aqua explains further that "[s]ince the forecast is not available for the quarters in the FPFTY, the Company uses the last available forecasted quarterly percentage change and uses that as the annual rate to multiply inflation eligible expenses." Aqua M.B. at 59 (citing Aqua St. 3 at 3).

The OCA argued that the adjustment is a blanket inflation adjustment which does not utilize a targeted approach. Aqua M.B. at 60 (citing OCA St. 1 at 34-35). The OCA provided that Aqua's adjustments for estimated blanket inflation are inconsistent with the law and should be removed, reducing FPFTY expenses by $1.07 million. OCA M.B. at 28 (citing OCA St. 1 at 34-25; OCA Exh. LA-2, Sch. C-5; Table II (Water, Wastewater Base, Limerick, East Bradford, Cheltenham, East Norriton, New Garden)). The OCA stated that Aqua did not adequately justify the purpose behind its inflation adjustments. The OCA argued that Aqua is speculating regarding what increase, if any, is appropriate for those expenses. OCA M.B. at 28-29.

2. Recommended Decision

The ALJ agreed with the OCA that Aqua has not justified the use of a general price level adjustment to expenses. The ALJ noted that according to Aqua's witness, Mr. Christopher E. Manning, the general inflation factor would be applied to

22% of Aqua's total operating expenses. R.D. at 70 (citing Aqua St. 3-R at 3). The ALJ reasoned that while it may be simpler for Aqua to use a general inflation factor for a block of expenses, its simplicity belies the fact that Commission precedent requires specificity if an inflation factor is utilized. The ALJ explained that to permit a large, sophisticated utility like Aqua to use a general inflation factor on a group of expenses as proposed here would incentivize less accurate tracking of expenses and would disincentivize Aqua from controlling its costs. In the ALJ's view, Aqua has not demonstrated that tracking the changes in these expenses individually is unduly burdensome. R.D. at 70.

The ALJ recommended that the Company's full inflation adjustment should be removed as it is not supported by record evidence and contradicts precedent to approve inflation adjustments only when the proposed adjustments are specific and not too general. The ALJ recommended an adjustment of $864,335 for water operations and $205,560 for wastewater operations. The wastewater adjustments are comprised of decreases for Wastewater Base, Limerick, East Bradford, Cheltenham, East Norriton, and New Garden of $145,368, $23,275, $6,828, $8,719, $8,665, and $12,705, respectively. These adjustments are reflected in each rate case table under Table II, Row "General Inflation" of the Recommended Decision Appendix. As noted in Table VI of the Recommended Decision Appendix for each rate zone, the cash working capital adjustment resulting from this general inflation adjustment is recommended to be assigned to a general expense account for each rate zone that uses a number of lag days that is equal to the weighted average O&M Expense lag days for each rate zone after all other adjustments are applied. R.D. at 70-71, R.D. Appendix, Table II, Table VI.

3. Aqua Exception No. 7 and Replies

In its Exception No. 7, Aqua provides that the Commission has repeatedly held that general price adjustment factors may be applied to expenses not separately adjusted, where the utility has demonstrated the adjustments are adequately supported and relatively conservative. Aqua Exc. at 27 (citing Aqua M.B. at 61-62). Aqua states that the Commission "has consistently accepted inflation adjustments where supported by historic data demonstrating that the utility has experienced cost increases that exceed the claimed inflation increases." Aqua Exc. at 27 (citing Aqua M.B. at 62 (quoting *Pa. PUC v. Philadelphia Suburban Water Company*, Docket Nos. R-00016750, 2002 Pa. PUC LEXIS 55 (Order entered July 8, 2002) (*Philadelphia Suburban Water 2002*) at *55).

Aqua avers that the ALJ incorrectly stated that the adjustment lacked specificity. Aqua Exc. at 27 (citing R.D. at 70). Aqua notes that its Main Brief provided details on the proposed adjustment and demonstrated that it uses an inflation factor well below the historical cost increases the Company has faced. Aqua Exc. at 28 (citing Aqua M.B. at 63).

In its reply to Aqua Exc. No. 7, the OCA contends that the ALJ correctly disallowed the Company's proposed general price level adjustment. The OCA avers that Aqua's argument that the Commission has approved similar inflation adjustments by the Company ignores that the Commission has historically required utilities to provide greater specificity about these adjustments. OCA R. Exc. at 4 (citing OCA M.B. at 28-30; OCA R.B. at 14).

According to the OCA, Aqua's claim that the ALJ "ignores" precedent by disallowing this general inflation adjustment is incorrect. OCA R. Exc. at 4 (citing Aqua Exc. at 27). The OCA provides that the Commission has historically disallowed speculative inflation factors. OCA R. Exc. at 4 (citing *Pa. PUC v. Philadelphia Elec. Co.*, 58 Pa. P.U.C. 7 (1983) (*PECO 1983*); *National Fuel Gas Dist. Corp. v. Pa. PUC*, 677 A.2d 861 (Pa. Cmwlth. 1986) (*NFG 1986*)). The OCA notes that Aqua provided only three examples of expenses that have grown at rates which exceed the Company's proposed inflation factor. OCA R. Exc. at 4 (citing Aqua St. 3 R at 3-4). The OCA argues that the proposed inflation adjustment should not be approved because Aqua has provided no evidence about the other operating expenses to which the inflation factor would be applied. OCA R. Exc. at 4 (citing R.D. at 70; OCA M.B. at 30; OCA R.B. at 15).

The OCA finds ALJ Long's concern about setting a precedent which would allow large utilities such as Aqua to apply a general inflation factor to unspecified expenses is well-founded. OCA R. Exc. at 4 (citing R.D. at 70). The OCA agrees with the ALJ that if the Commission were to approve Aqua's entire proposed inflation adjustment based solely on three expense examples provided by Aqua, it would open the door for other large utilities to propose unjustified blanket inflation expense adjustments in future rate cases. The OCA concludes that ALJ Long correctly disallowed Aqua's proposed inflation adjustment, reducing FPFTY expenses by $1.07 million. OCA R. Exc. at 4 (citing R.D. at 70-71; OCA M.B. at 28-30; OCA R.B. at 15; OCA Table II (Water, Wastewater Base, Limerick, East Bradford, Cheltenham, East Norriton, New Garden)).

4. Disposition

Aqua's proposed General Price Adjustment applies to approximately 22% of Aqua's O&M expenses. The OCA acknowledged that in our recent decision in *Pa. PUC v. PECO Energy Co. – Gas Division*, Docket No. R-2020-3018929, Order entered June 22, 2021 (*PECO Gas 2021*), we approved an inflation adjustment. However, as the OCA correctly notes, the company in that proceeding used a more targeted approach to an inflation adjustment than Aqua proposed. OCA St. 1 at 35. More specifically, the Commission approved an inflation adjustment for regulatory Commission expenses but denied an inflation adjustment in that same case that the Commission found less specific. *See PECO Gas 2021* at 88, 95-96.

The Commission recently denied a blanket increase by Wellsboro Electric Company[50] of 3% inflation applied to FTY expenses to estimate FPFTY expenses.

In *Wellsboro 2020* the Commission stated:

> [T]he Company did not demonstrate that making this blanket adjustment to each expense claim directly relates to the actual costs expected to be incurred in each expense account in the FPFTY.

Wellsboro 2020 at 40.

In both its briefs and its Exceptions, Aqua also cited to *Philadelphia Suburban Water 2002*, to justify the use of an inflation factor for 22% of expenses. *See* Aqua M.B. at 62; Aqua Exc. at 27. However, we note in that case, the inflation adjustment was more closely targeted to the inflation adjustment and "was applied only to those miscellaneous employee expenses not otherwise specifically adjusted." *Philadelphia Suburban 2002* at *51 (citing R.D. at 37-38). We agree with the ALJ that Aqua has not justified the use of a general price level adjustment to expenses "not specifically adjusted in this case or not subject to inflation." R.D. at 70. We also agree that allowing Aqua to apply a general inflation adjustment to a block of expenses could incentivize less accurate tracking of expenses and a less rigorous approach to controlling costs for those expenses. The application of a General Price Adjustment to 22% of expenses is neither targeted nor specific. We find the ALJ's recommendation to deny Aqua's use of a General Price Adjustment to be reasonable. Therefore, we shall adopt the ALJ's recommendation to remove the Company's entire claimed amount of $864,335 for water operations and $205,560 for wastewater operations. As noted by the ALJ, the wastewater adjustments are comprised of decreases for Wastewater Base, Limerick, East

[50] *Pa. PUC, OCA, OSBA v. Wellsboro Electric Company*, Docket No. R-2019-3008208 (Order entered April 29, 2020) (*Wellsboro 2020*).

Bradford, Cheltenham, East Norriton, and New Garden of $145,368, $23,275, $6,828, $8,719, $8,665, and $12,705, respectively. These are outlined in Table II-Adjustments in each of the rate tables that are attached to Commission Tables Calculating Allowed Revenue Increase at the end of this Opinion and Order.

Based on the above discussion, Aqua Exception No. 7 is denied.

K. Chemicals and Purchased Power (Water) Expenses

1. Positions of the Parties

The OCA proposed to increase the Company's claimed Chemicals Expense for water operations by $66,787. R.D. at 71 (citing OCA St. 1 at 38). This adjustment is based on the OCA's proposed adjustment to Metered Residential Water sales, which estimates the Company's progress towards the return to pre-pandemic residential usage levels as slower than the Company predicts.

The OCA recommended a related negative adjustment of $96,312 to the Purchased Power expense. OCA M.B. at 30 (citing OCA St. 1 at 38; OCA Exh. LA-2, Sch. C-7; Table II (Water)).

I&E did not recommend adjustments to gas and electric O&M expenses. I&E M.B. at 39.

2. Recommended Decision

The ALJ did not recommend any adjustments to Aqua's claim for chemicals expense consistent with the ALJ's recommendations related to Metered Residential Water Sales revenue. R.D. at 71.

3. OCA Exception No. 1

In its Exception No. 1, the OCA recommends an increase to residential revenues of $2.757 million based on a slower return of residential revenues than Aqua predicted. Associated with that more gradual revenue increase, the OCA recommends a negative adjustment of $66,787 to the Chemicals Expense for water operations and a negative adjustment to Purchased Power expense of $96,312. OCA Exc. at 1-2 (citing OCA M.B. at 30; OCA Table II (Water)). The OCA also recommends that the Company's CWC be adjusted to reflect this revenue adjustment and based on the expense adjustments it recommended. OCA Exc. at 2 (citing OCA M.B. at 22; OCA Table II (Water), OCA Table II (Wastewater)).

4. Disposition

As provided in our disposition of the OCA's Exception No. 1 in Section VII. D. of this Opinion and Order, *supra*, we denied the OCA Exception No. 1. Therefore, we shall also decline to make the OCA's requested adjustments to the Chemicals Expense and the Purchased Power Expense for water operations.

L. Depreciation - Amortization Expense Adjustment – Water – Phoenixville Acquisition

1. Positions of the Parties

Aqua has requested a positive acquisition adjustment of $2,315,440 to its rate base for the Phoenixville water system as of the end of the FPFTY. Aqua M.B. at 19 (citing Aqua Exh. 1-A, Sch. G-3). Aqua has provided a claim of $121,865 for amortization expense associated with the positive acquisition adjustment to rate base. Aqua M.B. at 58.

Both I&E and the OCA contended that the amortization expense associated with the Phoenixville acquisition should be disallowed. Aqua M.B. at 58 (citing I&E St. 3 at 11, OCA St. 1 at 30). I&E recommended that the Phoenixville acquisition adjustment be denied, which reduces rate base by $2,315,440 and also reduces the annual amortization expense by $121,865, which is expressed as a depreciation expense. I&E M.B. At 20 (citing I&E St. 3 at 10-11; I&E St. 3-SR at 7). I&E recommended that the Company's total annual amortization expense be reduced by $121,865. I&E M.B. at 21 (citing I&S St. 3-SR at 3-7).

2. Recommended Decision

The ALJ recommended that $2,437,305 be removed from Aqua's rate base, and the concomitant adjustments should be made to the accrued depreciation reserve and annual amortization expense which is expressed as a depreciation expense. R.D. at 44 (citing Aqua M.B. at 18). *See* also R.D. at 44, n. 27.

3. Aqua Exception No. 2

In its Exception No. 2, Aqua avers that the ALJ erred by disallowing Aqua's water rate base claim related to the acquisition of the Phoenixville Water system. Aqua Exc. at 15-18.

4. Disposition

As provided in our disposition of Aqua's Exception No. 2 in Section VI.B., *supra*, we denied the Company's Exception No. 2 and found the ALJ's recommended negative adjustment to rate base of $2,437,305 to be reasonable. Accordingly, we find that the concomitant adjustments as recommended by the ALJ should be made to the accrued depreciation reserve and the annual amortization expense, which is expressed as a depreciation expense in this filing. The adjustments are reflected in our Commission Tables Calculating Allowed Revenue Increase, attached to this Opinion and Order at Table II-Water, Rows “Acquis. Adj. – Phoenixville” and “Amort. Phoenixville Acquis. Adj.”

M. Cash Working Capital

1. Positions of the Parties

Aqua explained that CWC is the capital requirement arising from the difference between: (1) the lag in the receipt of revenue for rendering service; and (2) the lag in the payment of cash expenses incurred to provide that service. Aqua explained further that its CWC claims for water and wastewater operations include the necessary working capital associated with O&M expense, taxes, and interest. Aqua M.B. at 32 (citing Aqua Exh. 1-A(a), Sch. G-5; Aqua Exh. 1-B(b), Sch. G-5). For water operations, its CWC amount claimed is $1,736,000. Aqua M.B. at 32 (citing Aqua Exh. 1-A(a), Sch. G-5). For wastewater base operations, its CWC amount claimed is $550,000. Aqua M.B. at 31 (citing Aqua Exh. 1-B(b), Sch. G-5).

Aqua stated that no parties challenged the Company’s lead/lag study or its calculation of: (a) the average lag days in payment of expenses, taxes or interest, (b) the average lag day in receipt of revenues, or (c) the average lag days between payment of expenses and receipt of revenue. Aqua M.B. at 31 (citing Aqua St. 1 at 27 (describing the results of the lead/lag study)).

I&E provided that it agrees with the Company’s use of a lead/lag study to measure how many days exist on average between the midpoint of the service period and the date the payment is received. I&E M.B. at 38 (citing I&E St. 1 at 30). Based on I&E’s recommended expense adjustments, I&E recommended a cash working capital allowance for Water of $1,679,000 or a reduction of $57,000 from the Company's claimed $1,736,000. I&E did not recommend an adjustment for cash working capital for Wastewater Base or the other wastewater acquisitions. I&E M.B. at 38 (citing I&E St. 1-SR at 31).

The OCA averred that there should be a negative adjustment of $9.433 million for Interest for Water Operations, and the proposed rate base amount for CWC should be reduced by $0.718 million. OCA M.B. at 22 (citing OCA St. 1 at 24). The OCA explained that this adjustment is based on negative adjustments to Long Term Debt-Interest and Pennvest Interest. OCA M.B. at 22 (citing OCA St. 1 at 24; OCA Exh. LA-2, Sch. B-3). The OCA stated that, excluding the Section 1329 acquisitions by the Company, there should be an approximate negative $440,000 adjustment for Interest for Aqua's wastewater rate base and recommended a CWC requirement that is $28,000 lower than Aqua's proposed CWC allowance for Wastewater base operations. The OCA stated that this adjustment is made based on a negative adjustment to Long Term Debt-Interest, and both adjustments are made at the recommendation of the OCA's witness, Mr. Smith. OCA M.B. a 22 (citing OCA St. 1 at 25; OCA Exh. LA-2, Sch. B-3).

The OCA also recommended an adjustment to CWC based on its recommended adjustment to residential water sales revenue. OCA Exc. at 2.

2. Recommended Decision

The ALJ recommended adjustments to CWC related to the General Price Level Adjustment made as detailed in that discussion *supra.* R.D. at 71.

Overall, the ALJ noted that Aqua's claims for CWC have been adjusted based on the recommended adjustments to rate base, O&M expenses and taxes in the tables attached as appendices to the Recommended Decision. R.D. at 45.

3. OCA Exception No. 1 and Replies

In its Exception No. 1, the OCA insists that CWC should be adjusted to reflect the OCA's recommended residential revenue adjustment and its expense adjustments. OCA Exc. at 2 (citing OCA M.B. at 22; OCA Table II (Water); OCA Table II (Wastewater)).

In its reply to the OCA Exception No. 1, Aqua contends that OCA's recommended residential revenue adjustment was correctly rejected by the ALJ. Aqua R. Exc. at 1-2.

4. Disposition

As provided in our disposition for OCA Exception No. 1 in Section VII.E., *supra,* we denied OCA Exception No. 1. We decline to make the OCA's related requested adjustments to CWC. Accordingly, we shall also decline to make the OCA's requested changes to CWC related to Long Term Debt-Interest and Pennvest Interest.

Based on the above discussion of the adjustments to Aqua's individual expense claims, we have approved a total downward adjustment to the Company's water

O&M expenses of $1,900,892.[51] The cash working capital components related to interest and dividends, taxes, and O&M expense result in a net overall increase of $199,948 to the Company's water CWC.[52]

Additionally, we have approved a total downward adjustment to the Company's wastewater O&M expenses of $232,643. The cash working capital components related to interest and dividends, taxes, and O&M expense result in a net overall increase of $362,667 to the Company's wastewater CWC. As stated in Section VI.C, *supra,* this is broken down as follows: (1) a net increase to the CWC component for Wastewater-Base of $216,340,[53] which reflects, in part our downward adjustment to O&M expenses of $150,101; (2) a net increase to the CWC component for Wastewater-Limerick of $76,673,[54] which reflects, in part our downward adjustment to

[51] As set forth in Table II-Water in the Commission Tables Calculating Allowed Revenue Increase, attached to this Opinion and Order, our net total reduction to the Company's water expenses claim is $1,894,043. This figure includes a total reduction of $1,900,892 related to our downward adjustments to the Company's water expense claims for general liability insurance expense, general price level adjustment, and SERP expense, as discussed in this Expenses section. This is netted against a total increase to expenses of $5,849 related to water contract revenues and concomitant forfeited discounts, as discussed in Section VII of this Opinion and Order, *supra.* [(-$1,900,892+$5,849=$-$1,895,043]. It is our $1,900,892 reduction to the Company's expenses that flows to our downward adjustment to Cash Working Capital – O&M Expense that is described in the next footnote.

[52] As set forth in Table II-Water, the $275,473 addition is the net of: (1) an increase of $4,950 to Cash Working Capital – Interest and Dividends; (2) an increase of $431,945 to Cash Working Capital – Taxes; and (3) a decrease of $161,422 to Cash Working Capital – O&M Expense. [($4,950 + $431,945 - $161,422) = $275,473].

[53] As set forth in Table II-Wastewater-Base, the $216,340 addition is the net of: (1) a decrease of $945 to Cash Working Capital – Interest and Dividends; (2) an increase of $226,646 to Cash Working Capital – Taxes; and (3) a decrease of $9,361 to Cash Working Capital – O&M Expense. [(-$945 + $226,646 - $9,361) = $216,340].

[54] As set forth in Table II-Wastewater-Limerick, the $76,673 addition is the net of: (1) a decrease of $389 to Cash Working Capital – Interest and Dividends; (2) an increase of $78,550 to Cash Working Capital – Taxes; and (3) a decrease of $1,488 to Cash Working Capital – O&M Expense. [(-$389 + $78,550 - $1488) = $76,673].

O&M expenses of $27,778; (3) a net increase to the CWC component for Wastewater-East Bradford of $9,669,[55] which reflects, in part our downward adjustment to O&M expenses of $7,802; (4) a net increase to the CWC component for Wastewater-Cheltenham of $54,249,[56] which reflects, in part, our downward adjustment to O&M expenses of $16,469; (5) a net increase to the CWC component for Wastewater-East Norriton of $24,706,[57] which reflects, in part our downward adjustment to O&M expenses of $14,318; and (6) a reduction to the CWC component for Wastewater-New Garden of $18,970,[58] which reflects, in part our downward adjustment to O&M expenses of $16,175.

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55 As set forth in Table II-Wastewater-East Bradford, the $9,669 addition is the net of: (1) an increase of $250 to Cash Working Capital – Interest and Dividends; (2) an increase of $9,729 to Cash Working Capital – Taxes; and (3) a decrease of $310 to Cash Working Capital – O&M Expense. [($250 + $9,729 - $310) = $9,536].

56 As set forth in Table II-Wastewater-Cheltenham, the $54,249 addition is the net of: (1) a decrease of $431 to Cash Working Capital – Interest and Dividends; (2) an increase of $56,325 to Cash Working Capital – Taxes; and (3) a decrease of $1,645 to Cash Working Capital – O&M Expense. [(-$431 + $56,325 - $1,645) = $54,249].

57 As set forth in Table II-Wastewater-East Norriton, the $24,706 addition is the net of: (1) a decrease of $369 to Cash Working Capital – Interest and Dividends; (2) an increase of $25,827 to Cash Working Capital – Taxes; and (3) a decrease of $752 to Cash Working Capital – O&M Expense. [(-$369 + $25,827 - $752) = $24,706].

58 As set forth in Table II-Wastewater-New Garden, the $18,970 reduction consists of: (1) a decrease of $378 to Cash Working Capital – Interest and Dividends; (2) a decrease of $18,230 to Cash Working Capital – Taxes; and (3) a decrease of $362 to Cash Working Capital – O&M Expense. [(-$378 - $18,230 - $362) = – $18,535].

IX. Taxes

A. Payroll Tax Expense

1. Positions of the Parties

Aqua's initial payroll tax claim included a payroll tax expense of $3,163,655, based on its vacancy rate of 2.50%. Aqua Exh. 1-A, Sch. D-2.5. The OCA submitted that a more accurate vacancy rate would be 2.88%. OCA M.B. at 33. Aqua and I&E accepted the OCA recommended 2.88% vacancy rate. Aqua M.B. at 88, I&E M.B. at 37. Accordingly, the Company updated its claim for payroll tax expense to $3,151,838. Aqua Exh. 1-A(a), Sch. D-2.5.

2. Recommended Decision

The ALJ remarked that Aqua's payroll tax claim was updated in rebuttal testimony to reflect the Company's acceptance of a revised vacancy rate of 2.88%. As a result, it was not necessary for the ALJ to make further adjustments to the payroll taxes. R.D. at 71-72.

3. Disposition

No Exceptions were filed objecting to the ALJ's recommendation on this issue. We find that the ALJ's recommendation is supported by ample record evidence and is just and reasonable. Therefore, we shall adopt Aqua's payroll tax claim based on a 2.88% vacancy rate.

B. Income Taxes

1. Positions of the Parties

Aqua stated its interest expense deduction claimed for ratemaking purposes was calculated using the interest synchronization method, which multiplies the weighted cost of debt in the Company's capital structure by the Company's rate base. Aqua Exh. 1-A, Sch. E-1 at 1. The OCA calculated Aqua's interest synchronization using the OCA's recommended hypothetical capital structure, *infra*. OCA R.B. at 39. As Aqua disagrees with the OCA's proposed hypothetical capital structure, it also opposes the OCA's proposed adjustment to the interest expense deduction. Aqua R.B. at 36.

2. Recommended Decision

As will be discussed more fully in Section X.B, *infra,* the ALJ rejected the OCA's use of a hypothetical capital structure for Aqua. Thus, the ALJ denied the OCA's claim regarding interest synchronization as it relates to income taxes. R.D. at 71-72.

3. Disposition

No Exceptions were filed objecting to the ALJ's recommendation on this issue. We find that the ALJ's recommendation is supported by ample record evidence and is just and reasonable. Therefore, we shall adopt the ALJ's recommendation that Aqua's interest synchronization method be employed, using the Company's capital structure, to calculate its interest expense deduction.

C. Tax Repair Deduction

1. Positions of the Parties

Aqua has proposed to carve-out $4 million per year for its repair deductions, in the calculation of income tax expense, on the basis that it has identified a portion of its annual repair deductions as being uncertain of passing an IRS audit. To account for the "uncertain" repair deductions, Aqua has established a reserve to reduce rate base. Aqua M.B. at 90-92. Any IRS disallowance would be offset against the reserve. Aqua explained that FIN 48 is related to the Company's practice of claiming the greatest tax-repair deductions it believes are reasonable, it recognizes that the IRS may ultimately disallow certain claims. Aqua M.B. at 91; Aqua St. 8-R at 6. Aqua's witness, Ms. Christine L. Saball, noted the IRS has yet to issue guidance regarding what capital additions will qualify as repairs, and thus there is uncertainty regarding the actual tax repair deductions that will be allowed. *Id.*

The OCA contended that Aqua's "flow through" treatment for its tax repair deductions is "unusual" and can result in large amounts of excess earnings between rate cases. OCA M.B. at 77; OCA R.B. at 37. The OCA also proposed to eliminate the Company's $4 million adjustment for FIN 48 uncertain tax positions. According to the OCA, Aqua's FIN 48 adjustment for uncertain tax positions should reflect the amount expected to be deducted for repairs without any offset for uncertain tax positions, relying on guidance provided by the Federal Energy Regulatory Commission (FERC) for energy utilities. OCA M.B. at 81; OCA St. 1 at 34-35.

2. Recommended Decision

The ALJ was not convinced that removal of the FIN 48 adjustment from the tax repair deduction is required. R.D. at 73. The ALJ noted that the OCA contended that this treatment of the tax repair deduction "may" result in excess earnings. However, the ALJ was persuaded by Aqua's explanation that "including the FIN 48 adjustment protects customers because they will not be required to return to the Company disallowed deductions, because those deductions will not have been reflected in rates." R.D. at 74 (citing Aqua St. 8-R at 7). The ALJ was also persuaded by how the Company handles the FIN 48 exclusion with regard to its rate base. In this regard, the ALJ noted the Company's statement that "[t]o compensate customers for the time value of money benefits of the FIN 48 exclusion, the Company deducts from rate base the reserve balance established for all years in which the challenged deductions are claimed." *Id*.

The ALJ was further persuaded to recommend that the Company's tax repair deduction be approved, based on the following Company arguments that: (1) shareholders will not receive income for the tax effect of the FIN 48 adjustment, and the rate base deduction ensures that customers receive the time value of money benefit related to the deferral of the uncertain tax position; (2) if, in the future, the IRS allows the full tax repair deduction, then the reserve balance will be returned to customers in rates; (3) if the full deduction is disallowed, as the Company assesses is likely, the reserve will be debited for the disallowed amount; and (4) customers will receive the benefit of the reserve balance amortized as a deduction to tax expense in future rate cases. R.D. at 74 (citing Aqua St. 8-R at 6-7).

Thus, the ALJ recommended that the Commission permit Aqua to continue utilizing the flow-through treatment of tax repair deductions which were approved in the settlement of Aqua's 2018 base rate case. Similarly, the ALJ recommended the Commission reject the OCA's objection to Aqua's "collar mechanism."[59] The ALJ

[59] The ALJ noted that the OCA did not address its witness' argument in surrebuttal testimony opposing the collar mechanism in its Main Brief. R.D. at 74, n.120.

concluded that there is no convincing evidence that this tax treatment has resulted in excess earnings or has otherwise harmed ratepayers. R.D. at 74.

3. OCA Exception No. 10 and Replies

In its Exception No. 10, the OCA excepts to the ALJ's recommendation and states that the tax repair deduction should only include those repairs that Aqua expects to claim for tax purposes and that the proposed carve-out is inappropriate for ratemaking purposes. The OCA also states that it does not take issue with the "collar mechanism" recommended by the ALJ. However, the OCA opines that if any "collar" amount around the repairs deduction amount that is used to compute income tax expense were to be used going-forward, the "collar" should be no wider than $4 million per year. OCA Exc. at 14-15.

In its Replies, the Company asserts that the ALJ correctly concluded the FIN 48 adjustment appropriately accounts for a portion of Aqua's claimed repairs expense deduction that will likely be disallowed by the IRS. Aqua notes the "collar" was established to address concerns that the claimed deduction could substantially vary from the actual deduction. Aqua R. Exc. at 8-9.

4. Disposition

We find that the ALJ's recommendation allowing Aqua to implement the FIN 48 adjustment as well as the "collar" up to $4 million, is supported by ample record evidence and is just and reasonable. Accordingly, we shall adopt the ALJ's recommendation on this issue and deny the OCA's Exception No. 10.

X. Rate of Return

Rate of Return is one of the components of the utility's Revenue Requirement formula, outlined, *supra.* Specifically, a utility's rate of return is the amount of revenue an investment generates in the form of net income and is usually expressed as a percentage of the amount of capital invested over a given period of time. A fair and reasonable overall rate of return is one that will allow the utility an opportunity to recover those costs prudently incurred by all classes of capital used to finance the rate base during the prospective period in which its rates will be in effect. I&E M.B. at 42.

A. Proxy Groups

To estimate a utility's cost of equity,[60] or return on equity, a proxy group of similar companies is used. This group of companies acts as a benchmark to satisfy the long-established guideline of utility regulation that seeks to provide the subject utility the opportunity to earn a return similar to that of enterprises with corresponding risks and uncertainties. A proxy group is generally preferred over the use of data exclusively from any one company, because it has the effect of smoothing out potential anomalies associated with a similar company and, therefore, is a more reliable measure. I&E St. 2 at 7.

1. Description of the Parties' Proxy Groups

Aqua used a proxy group of eight companies, which it referred to as the "Water Group." In arriving at its Water Group, the Company applied the following criteria:

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[60] The Parties' positions regarding the cost of common equity will be discussed in more detail in Section X.D of this Opinion and Order, *infra.*

1. Each company was listed in the "Water Utility Industry" section (basic and expanded) of The Value Line Investment Survey (*Value Line*); and

2. The company's stock was publicly traded.

Aqua submitted that its size and financial risk are similar to the companies in its Water Group and, therefore, the Water Group provides a reasonable basis for measuring the Company's cost of equity. Aqua St. 7 at 13, 18.

I&E's proxy group consisted of seven companies. In selecting a proxy group of companies that are similar to Aqua, I&E applied the following criteria to *Value Line*'s "Water Utility" Company group:

1. Fifty percent or more of the company's revenue were generated from the water utility industry;

2. The company's stock was publicly traded;

3. Investment information for the company was available from more than one source, including *Value Line*;

4. The company must not be currently involved in an announced merger or the target of an announced acquisition; and

5. The company must have four consecutive years of historic earnings data.

I&E St. 2 at 8-9.

I&E explained that Aqua's Water Group contains all seven companies in its own proxy group. However, I&E excluded Artesian Resources Corporation from its own proxy group because it violates I&E's third proxy group criterion, *supra.* In this regard, I&E explained that Artesian Resources Corporation does not have a *Value Line* report, and therefore, does not have projected dividends per share or projected earnings growth rate information. I&E St. 2 at 10-11; I&E St. 2-SR at 2-3.

The OCA chose to use the same proxy group as selected by the Company. According to the OCA, while different arguments could be raised for the inclusion or exclusion of a particular utility within the proxy group, by using the same proxy group as the Company, the OCA has removed the selection of the proxy group as a variable in analyzing the appropriate rate of return. In the OCA's view, utilizing the Company's proxy group is valuable in focusing on the primary factors driving the cost of equity estimate and in demonstrating why Aqua's conclusions regarding its proposed rate of return are unreasonable. OCA M.B. at 60-61.

Aqua claimed that I&E's decision to exclude Artesian Resources Corporation from its proxy group was erroneous. Aqua submitted that the composition of a proxy group should not be dependent upon whether relevant data is available from a specific source. Rather, Aqua argued, there is other source data available for Artesian Resources Corporation, as set forth in Aqua Exhibit 4-A, such that it should be included in the proxy group used in this proceeding. Aqua M.B. at 110.

Table 3, below, provides a summary of the companies each party proposed to be used in their respective water proxy groups:

Aqua	OCA	I&E
American States Water	American States Water	American States Water
American Water Works Company	American Water Works Company	American Water Works Company
Artesian Resources Corporation	Artesian Resources Corporation	California Water Serv. Group
California Water Serv. Group	California Water Serv. Group	Essential Utilities, Inc.
Essential Utilities, Inc.	Essential Utilities, Inc.	Middlesex Water Company
Middlesex Water Company	Middlesex Water Company	SJW Corporation
SJW Corporation	SJW Corporation	York Water Company
York Water Company	York Water Company	

Table 3: Summary of the Proposed Water Proxy Groups in this Proceeding

Aqua St. 1 at 13; I&E St. 2 at 9; OCA St. 3 at 17.

As discussed below, the ALJ recommended that the Commission adopt the proposals set forth by I&E in setting a cost of equity for Aqua in this proceeding, including the use of I&E's proxy group. R.D. at 77-81. No Party specifically challenged the use of I&E's proxy group in the Exceptions phase of this proceeding. Finding I&E's proxy group criteria to be reasonable, and finding the companies contained therein to be representative of Aqua, we shall adopt I&E's proposed proxy group.

B. Capital Structure Ratios

A utility's capital structure represents how the utility has financed its rate base with different sources of funds. Determining the appropriate capital structure is crucial in developing the weighted cost of capital, which, in turn, determines the overall rate of return in the revenue requirement equation, *supra*. The primary funding sources for the utility are long-term debt and common equity. Additionally, a capital structure may include preferred stock and/or short-term debt. However, the Company is financed only with long-term debt and common equity. I&E St. 2 at 11.

1. Positions of the Parties

Aqua proposed a capital structure of 53.95% common equity and 46.05% long-term debt, which represents its projected capital structure as of the end of the FPFTY ending March 31, 2023. Aqua explained that it based its FPFTY capital structure upon its actual capital structure at the HTY ended March 31, 2021 and made adjustments to reflect events that will occur during the FTY and FPFTY. Aqua continued that these changes are to finance the Company's net rate base additions of approximately $557 million in the FTY and FPFTY. Specifically, Aqua included additional debt of $190 million to be issued in the FPFTY. In addition, Aqua projected the retention of approximately $269.7 million in earnings over the period, and the infusion of an additional $100 million in equity. Aqua M.B. at 102.

Aqua argued that the Commission has determined in previous proceedings that a utility's actual capital structure should be utilized unless there is a finding that it is atypical or too heavily weighted to either the debt or equity side. Aqua M.B. at 103-04 (citing *2012 PPL Order*). According to Aqua, this policy was recently affirmed in *Columbia Gas*. Aqua insisted that its common equity ratio falls within the ranges of the common equity ratios in its Water Group and in the proxy groups employed by both the OCA and I&E, and cannot be deemed "atypical." Accordingly, Aqua submitted that it is appropriate to use the Company's actual capital structure for ratemaking purposes. Aqua M.B. at 102, 103-07; Aqua R.B. at 42-45.

I&E recommended that the Commission adopt Aqua's proposed capital structure. According to I&E, the Company's claimed capital structure falls within the range of the 2020 capital structures for the companies in I&E's proxy group. I&E explained that the 2020 capital structures represented the most recent information available at the time of I&E's analysis. I&E further noted that the most recent five-year average range contains individual company capital structure ratios ranging from 39.93%

to 56.33% debt and 43.67% to 59.54% common equity, with an overall five-year average of 46.88% debt and 53.05% common equity. According to I&E, this five-year average capital structure is almost identical to the Company's claimed capital structure. I&E M.B. at 44; I&E St. 2 at 12.

In contrast, the OCA submitted that the Commission has the discretion to employ a hypothetical capital structure if the utility's actual capital structure is unreasonable or uneconomical. OCA M.B. at 57 (citing *Big Run Tel. Co. v. Pa. PUC*, 449 A.2d 86, 89 (Pa. Cmwlth. 1982) (*Big Run*)). Applying this to the instant proceeding, the OCA explained that it opposed the Company's proposed capital structure because the common equity ratio of nearly 54% that Aqua seeks to employ is significantly higher than the average of the eight regulated water utilities in its Water Group. According to the OCA, because this results in an unreasonably high cost of capital estimate, the Commission must impose a capital structure upon the Company that will not unfairly penalize its ratepayers and that is more reflective of one that might exist in a competitive environment. In the OCA's view, the use of a hypothetical capital structure will reduce costs to ratepayers, as opposed to increasing costs. OCA M.B. at 56, 58-59.

Specifically, the OCA sought to use a hypothetical capital structure of 50% common equity and 50% long-term debt to set rates for Aqua. The OCA explained that such a capital structure is reflective of the average capital structures of the companies in the Water Group used by Aqua. In addition, the OCA pointed out that the average debt ratio of the Company's Water Group is 50%, based on 2020 data. OCA R.B. at 28-29; OCA St. 3-SR at 3-4.

2. Recommended Decision

The ALJ recommended that Aqua's proposed capital structure of 53.95% common equity and 46.05% long-term debt be adopted. The ALJ acknowledged the

OCA's observation that the Commission has the discretion to employ a hypothetical capital structure where a company's actual capital structure is unreasonable or uneconomical. However, the ALJ concurred with Aqua that the legal standard in Pennsylvania for deciding whether to use a hypothetical capital structure is not whether the utility's capital structure deviates from the "average" capital structure of the proxy group, but whether the capital structure is outside the range of the capital structures of the companies in the proxy group. The ALJ echoed I&E that Aqua's claimed capital structure is within the range of the capital structures in I&E's proxy group and is, therefore, reasonable. R.D. at 77.

3. OCA Exception No. 8 and Replies

In its Exception No. 8, the OCA remains of the opinion that a hypothetical capital structure consisting of 50% common equity and 50% long-term debt should be utilized in setting just and reasonable rates for Aqua. The OCA reasons that Aqua's proposed capital structure is inappropriate because the equity component is 400 basis points (*i.e.,* 4.00%) higher than the average of the companies in Aqua's Water Group. Thus, the OCA submits that if the Commission were to adopt the ALJ's recommendation, then this would result in a return on equity and a revenue requirement that are too favorable to Aqua's investors because they would impose an unfair cost burden to the Company's ratepayers. The OCA reiterates its argument that the Commission has exercised its discretion to direct a utility to use a hypothetical capital structure where the utility's management adopts an actual capital structure that imposes an unfair cost burden on ratepayers. As such, the OCA claims that the Commission should reverse the recommendation of the ALJ and exercise its discretion in this current proceeding. The OCA insists that its proposed hypothetical capital structure will adequately balance the interests of both the Company's ratepayers and investors and will reflect a capital structure that might exist in a competitive environment. OCA Exc. at 10-11.

In its Replies to Exceptions, Aqua rebuts that the ALJ correctly recommended that the OCA's proposed hypothetical capital structure should be rejected. Aqua submits that the OCA's position disregards long-established Commission precedent for deciding whether to use a hypothetical capital structure in setting rates. Namely, Aqua restates its position that the Commission has consistently held that if a utility's actual capital structure is within the range of a similarly situated proxy group of companies, then rates are set based on the utility's actual capital structure. Aqua maintains that its capital structure falls within the range of the companies in its Water Group and should be adopted. Aqua R. Exc. at 7.

In its Replies to Exceptions, I&E declines to offer a specific reply to the OCA's Exception No. 8. Rather, I&E simply reinforces its position that the Company's claimed capital structure should be adopted. I&E R. Exc. at 15.

4. Disposition

We shall deny the OCA's Exception No. 8 and adopt the ALJ's recommendation to use Aqua's actual capital structure, consistent with the following discussion.

Like the ALJ, we note the veracity of the OCA's statement that the Commission has the discretion to employ a hypothetical capital structure where a company's actual capital structure is unreasonable or uneconomical. However, because we find no merit in the OCA's arguments that the Company's actual capital structure is either unreasonable or uneconomical, we shall decline to exercise this discretion in the instant proceeding.

The use of an actual capital structure represents the Company's decision, in which it has full discretion, on how to capitalize its rate base. This actual capitalization forms the basis upon which Aqua attracts capital. *See 2012 PPL Order* at 68; *Columbia Gas* at 116; *PECO Gas* at 144. For example, Aqua's long-term debt cost rate of 4.00%, discussed, *infra,* which all Parties have accepted for ratemaking purposes, fully reflects the capitalization determined by the Company to be appropriate.

In both *Columbia Gas* and *PECO Gas,* we reaffirmed the legal standard in Pennsylvania for deciding whether to use a party's proposed hypothetical capital structure in setting rates, *i.e.*, we stated that if a utility's actual capital structure is within the range of a similarly situated proxy group of companies, rates are set based on the utility's actual capital structure. *Columbia Gas* at 116; *PECO Gas* at 144. More specifically, we reaffirmed this standard, which we articulated in the *2012 PPL Order,* as follows:

> Absent a finding by the Commission that a utility's actual capital structure is atypical or too heavily weighted on either the debt or equity side, we would not normally exercise our discretion with regard to implementing a hypothetical capital structure.

Columbia Gas at 116-17; *PECO Gas* at 144-45 (citing *2012 PPL Order* at 68).

We find that the record developed in this proceeding lends support to the same conclusion that we reached in the *2012 PPL Order*, *Columbia Gas*, and *PECO Gas.* First, we note the testimony of I&E that Aqua's claimed capital structure falls within the range of the 2020 capital structures for the companies in I&E's proxy group, which we have determined to be the companies that are most representative of Aqua. The 2020 range consists of long-term debt ratios ranging from 39.93% to 56.33% and equity ratios ranging from 43.67% to 59.54%, with a five-year average of 46.88% for long-term debt and 53.05% for common equity. As I&E observed, the five-year average capital structure of the proxy group is nearly identical to the Company's claimed capital structure. *See* I&E St. 2 at 12.

Next, we note that using I&E's proposed proxy group, Aqua's witness, Mr. Paul R. Moul, provided the below chart in his rebuttal testimony, which we have set forth in Table 4. Namely, this chart details the forecasted common equity ratios for 2024 through 2026 for each of the companies in I&E's proposed proxy group, as outlined in *Value Line* as of October 8, 2021.

Company	**Projected Common Equity Ratio for 2024-2026**
American States Water	46.50%
American Water Works	39.00%
California Water Serv. Group	59.00%
Essential Utilities, Inc.	45.00%
Middlesex Water Company	60.00%
SJW Corporation	62.00%
York Water Company	62.50%
Average	**53.43%**

Table 4: Forecasted Common Equity Ratios for 2024 through 2026 for I&E's Water Proxy Group Companies

Aqua St. 7-R at 9-10. In comparing the Company's proposed common equity ratio to the forecasted common equity ratios of I&E's proxy group, we find that the above table lends support to Aqua's argument that its proposed actual common equity ratio falls well within the range of the forecasted common equity ratios of similarly situated water companies. In this regard, the data in this table demonstrates that Aqua's proposed common equity ratio of 53.95% is very close to the forecasted average common equity ratio for the entire proxy group of 53.43%. Furthermore, Aqua's proposed common equity ratio is below four of the companies in the I&E proxy group (*i.e.,* California Water Serv. Group, Middlesex Water Company, SJW Corporation, and York Water Company), whose forecasted common equity ratios range from 59.00% to 62.50%.

Based on the forgoing, we find that the record underscores that Aqua's proposed actual capital structure is not atypical and is within the range of reasonableness.

Therefore, we find no basis upon which to impose the OCA's hypothetical capital structure on the Company. Therefore, we shall deny the OCA's Exception No. 8 and adopt the ALJ's recommendation to use Aqua's proposed actual capital structure of 53.95% common equity and 46.05% long-term debt in this proceeding.

C. Cost of Debt

1. Positions of the Parties

Aqua proposed a cost of long-term debt of 4.00%. Aqua submitted that because no Party has challenged this debt cost rate, it should be adopted in the context of Aqua's actual capital structure ratios for debt, *infra*. Aqua M.B. at 107.

I&E noted that given Aqua's proposed capital structure ratios, *supra,* Aqua's proposal results in a weighted cost of debt of 1.84%. I&E submitted that Aqua's claimed cost rate of long-term debt is reasonable because it is representative of the industry, and it falls within I&E's proxy group's implied long-term debt cost range of 2.69% to 5.67% with an average implied long-term debt cost of 4.04%. I&E M.B. at 44-45.

2. Recommended Decision

The ALJ observed that no Party disagreed with Aqua's proposal to use its actual cost of long-term debt of 4.00%. Therefore, the ALJ recommended that the Company's proposal be adopted. R.D. at 77.

3. Disposition

No Party filed Exceptions on this issue with regard to the ALJ's recommendation. Finding the ALJ's recommendation to be reasonable, we shall adopt it without further comment. Accordingly, we shall approve a long-term debt cost rate of 4.00% for Aqua in this proceeding.

D. Cost of Common Equity

In the instant proceeding, Aqua, I&E, and the OCA presented a position on a reasonable ROE. The Parties' positions were generally developed through comparison groups' market data, costing models, reflection or rejection of risk and leverage adjustments, and a management performance adjustment, as will be further addressed, *infra*. Table 5, below, summarizes the cost of common equity claims made and the methodologies[61] used by the Parties in this proceeding:

Party	DCF	CAPM	RP	CE	ROE
Aqua	11.78%	13.40%	10.50%	12.80%	10.75%
I&E	8.90%	9.89%			8.90%
OCA	8.00%	6.40%			8.00%

Table 5: Summary of Each Party's proposed ROE

[61] As will be discussed below, in the following chart, DCF refers to the Discounted Cash Flow Method, CAPM refers to the Capital Asset Pricing Model, RP refers to the Risk Premium Method, and CE refers to the Comparable Earnings Method.

1. Methods for Determining the Cost of Common Equity

a. Discounted Cash Flow Method (DCF)

The DCF method applied to a proxy group of similar utilities, has historically been the primary determinant utilized by the Commission in determining the cost of common equity. *Pa. PUC v. City of Lancaster – Bureau of Water*, Docket No. R-2010-2179103 (Order entered July 14, 2011) at 56; *Pa. PUC v. PPL Electric Utilities Corp*., Docket No. R-00049255 (Order entered December 22, 2004) (*2004 PPL Order*) at 59. The DCF model assumes that the market price of a stock is the present value of the future benefits of holding that stock. These benefits are the future cash flows of holding the stock, *i.e.*, the dividends paid and the proceeds from the ultimate sale of the stock. Because dollars received in the future are worth less than dollars received today, the cash flow must be "discounted" back to the present value at the investor's rate of return.

(1) Positions of the Parties

Aqua's DCF model consists of a dividend yield plus a growth rate plus a leverage adjustment. The Company's DCF cost of common equity is 11.78%, which is calculated as follows:

	Dividend +	Growth +	Leverage =	DCF Cost Rate
Aqua DCF	1.94%	7.50%	2.34%	**11.78%**

Aqua's dividend yield calculation used six-month average dividend yields for the Water Group resulting in a dividend yield of 1.87%. The Company then adjusted this dividend yield for expected growth in dividends to produce a final dividend yield of 1.94%. Aqua St. 7 at 24.

Aqua principally relied upon five-year forecasts of earnings per share growth, as earnings growth appropriately measures the growth in price over time. The Company used three separate sources of projected earnings growth: IBES/First Call, Zacks, and *Value Line*. From this data, and applying judgment, the Company recommended a growth rate of 7.50%. Aqua St. 7 at 30.

As will be discussed in more detail below, in Section X.D.2, Aqua also argued that a leverage adjustment should be added to its DCF cost rate. The Company explained that a leverage adjustment is designed to adjust the DCF cost rate for the different percentage of debt in the capital structure calculated at market values of equity and long-term debt (the values used by investors) as compared to the percentage of debt in the capital structure at book value (the values used in the ratemaking process) to account for the greater financial risk created by a higher debt ratio when that cost rate is applied to a book value capitalization in utility proceedings. The Company argued that an unadjusted DCF greatly understates the cost of common equity because the proportion of market value common equity in the Water Group's capitalization was significantly higher than its proportion measure at book value. Aqua calculated an 11.78% return on equity using market value weighting. The Company calculated its leverage adjustment by subtracting the DCF return of 9.44% from the market value cost of equity of 11.78%. Accordingly, Aqua proposed to add a leverage adjustment of 234 basis points (*i.e.*, 2.34%) to its DCF cost of common equity calculation. Aqua St. 7 at 30-34, Sch. 10.

At the outset, I&E claimed the DCF method is in accordance with the Commission's historical use of the DCF as the primary methodology to determine a utility's cost of equity. I&E noted its recommendation is consistent with the methodology historically used by the Commission in base rate proceedings, most recently acknowledged in *Columbia Gas*. In I&E's view, it is now well settled that the Commission prefers the use of the DCF as the primary methodology in setting a utility's ROE in a rate case. Through the methodologies outlined in its testimony, I&E calculated that the DCF methodology produces a cost of common equity of 8.90%. I&E M.B. at 45-46.

I&E employed the standard DCF model, $k = D_1/P_0 + g$, where k is the cost of common equity, D_1 is the dividend expected during the year, P_0 is the current price of the stock, and g is the expected growth rate of dividends. I&E argued that a representative dividend yield must be calculated over a time frame that avoids problems of both short-term anomalies and stale data. I&E's dividend yield calculation placed equal emphasis on the most recent spot and the 52-week average dividend yields, resulting in an average dividend yield of 1.75%. I&E St. 2 at 21-22.

I&E used earnings growth forecasts to calculate its expected growth rate. I&E's earnings forecasts are developed from projected growth rates using five-year estimates from established forecasting entities for its proxy group of companies, yielding an average five-year growth forecast of 7.15%. I&E St. 2 at 23.

I&E submitted that Aqua's proposed leverage adjustment should be rejected because investors base their decisions on book value debt and equity ratios for regulated utilities, and not on market values, rendering any adjustment unnecessary. I&E also submitted that recent Commission precedent supports rejecting a utility's request for a leverage adjustment. I&E St. 2 at 42-44.

The OCA proposed an 8.00% DCF cost of equity. The OCA utilized a Quarterly Approximation DCF model that accounts for quarterly growth of dividends, instead of annual growth. OCA St. 3 at 25; OCA Exh. DJG-6. To obtain the stock price (P_0), the OCA selected a 30-day average for each company in the proxy group. OCA St. 3 at 27. The dividend term used by the OCA in the Quarterly Approximation DCF Model is the current quarterly dividend per share (d_0). The OCA states the model assumes that each quarterly dividend is greater than the previous one by $(1 + g)^{0.25}$. OCA St. 3 at 28.

Like I&E, the OCA submitted that Aqua's proposed leverage adjustment should be rejected. The OCA reasoned that Aqua based the leverage adjustment on its inaccurate and incorrect use of the Hamada formula. OCA St. 3 at 35-37.

b. Capital Asset Pricing Model (CAPM)

The CAPM uses the yield on a risk-free interest-bearing obligation (such as those issued by the U.S. Treasury) plus a rate of return premium that is proportional to the systematic risk of an investment. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return (Rf), the beta measure of systematic risk (β), and the market risk premium (Rm-Rf) derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (*i.e.*, market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Aqua, I&E, and the OCA each used the following standard CAPM formula:

$$k = R_f + \beta(R_m - R_f)$$

Where: k = the cost of equity and the remaining terms are as defined above.

(1) Positions of the Parties

Aqua determined the CAPM cost of equity as follows:

	R_f +	β x	$(R_m - R_f)$+	Size =	CAPM Cost Rate
Aqua CAPM	2.75%	1.07	9.00%	1.02%	**13.40%**

Aqua determined the risk-free rate to be 2.75% based on current and forecasted long-term Treasury Bond yields. Aqua also calculated a 9.00% premium for the risk/market premium component of the CAPM analysis, based upon the average historical data and forecasted returns. The Company used a leverage adjusted beta of 1.07, to reflect the financial risk associated with the rate setting capital structure that is measured at book value. Additionally, Aqua included a 1.02% size adjustment to its CAPM analysis. Therefore, Aqua calculated a CAPM cost of common equity of 13.40% for its Water Group. Aqua St. 7 at 41-43.

In calculating the CAPM cost of common equity, I&E chose the risk-free rate of return (Rf) of 1.98% from the projected yield on ten-year Treasury bonds as the most stable risk-free measure. I&E explained that its decision to use ten-year Treasury bonds balanced out issues related to the use of thirty-year long-term bonds and short-term T-Bills. I&E used the average of its proxy group betas from *Value Line* of 0.78. To arrive at a representative expected return on the overall stock market, I&E stated that it reviewed *Value Line*'s 1700 stocks and the S&P 500. I&E explained that the result of the overall stock market returns based on its CAPM analysis is 12.14%, which yields a cost of equity result of 9.89%. I&E St. 2 at 24-27. According to I&E, the 9.89% cost of equity from its CAPM should only be used as a point of comparison to its 8.90% DCF cost of capital. I&E St. 2 at 28.

In response to Aqua's CAPM analysis, I&E submitted that the Company used the same leverage adjustment for inflating its CAPM betas from 0.78 to 1.07 that was used for its DCF calculation. I&E asserted that such enhancements are unwarranted for beta in a CAPM analysis for the same reasons that enhancements are unwarranted for DCF results. In addition, I&E disagreed with Aqua's 102-basis point size adjustment applied to its CAPM analysis. I&E St. 2 at 47-49.

In its CAPM analyses, the OCA used a thirty-day average of thirty-year Treasury Bond yields to calculate a risk-free rate of 2.02%. OCA St. 3 at 40. The OCA found an average beta of 0.79 for its proxy group. OCA Exh. DJG-8. To find the equity risk premium, the OCA relied on expert surveys and an implied equity risk premium. The OCA calculated the implied equity risk premium by subtracting the risk-free rate from an implied expected market return. Using this data, the OCA concluded the proper CAPM return on equity is 6.4%. OCA St. 3 at 44-48.

c. Risk Premium (RP) Model and Comparable Earnings (CE) Model

Under the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The RP method determines the cost of equity by summing the expected public utility bond yield and the return of equities over bond returns (*i.e.*, the "equity premium") over a historical period, as adjusted to reflect lower risk of utilities compared to the common equity of all corporations. Aqua M.B. at 117-118; Aqua St. 7 at 35-36.

The CE method estimates a fair return on equity by comparing returns realized by non-regulated companies to the returns that a public utility with similar risk characteristics would need to realize in order to compete for capital. According to Aqua, because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into investor expectations for public utility returns. The firms selected for the CE method should be companies whose prices are not subject to cost-based price ceilings (*i.e.*, non-regulated firms) so that circularity is avoided. The CE method utilizes the concept of opportunity cost, wherein investors will likely dedicate their capital to the investment offering the highest return with similar risk to alternative investments. Aqua M.B. at 121; Aqua St. 7 at 43-44.

(1) Positions of the Parties

The Company determined the RP cost of common equity to be 10.50% as follows:

	Interest Rate +	Risk Premium =	RP Cost Rate
Aqua RP	3.75%	6.75%	**10.50%**

Aqua explained that the interest rate in its calculation is an estimated interest rate for A-rated public utility bonds, while the risk premium in its calculation is the average of historical risk premiums of long-term corporate bonds.

Aqua also performed a comparable earnings analysis based on the principle set forth by the United States Supreme Court that a utility should be afforded an opportunity to earn a return on its property equal to that being earned on investments in other businesses with corresponding risks and uncertainties. *See Bluefield, supra.* The Company's analysis identified non-regulated companies with comparable risk and produced a cost rate of 12.80%. Aqua M.B. at 121; Aqua St. 7 at 46.

I&E submitted that neither the RP method nor the CE method should be used in determining an appropriate cost of equity in a base rate proceeding. I&E pointed out that the RP method is a simplified version of the CAPM model. However, I&E noted that while the CAPM directly measures the systematic risk of the company through the use of beta, the RP method does not measure the specific risk of the company. As to the CE method, I&E charged that it is not market-based and relies upon historic accounting data. Further, I&E contended that under the CE method, the most problematic issue is determining what constitutes comparable companies. I&E St. 2 at 15, 19-20.

The OCA claimed that the Commission should disregard Aqua's RP and CE analyses. The OCA argued that Aqua's RP and CE analyses are flawed by the Company's choice of inputs and inclusion of adjustments. OCA M.B. at 73-75.

Therefore, I&E and the OCA recommended using the DCF method as the primary method to determine the cost of common equity and using the CAPM method as a comparison to the DCF results. Both I&E and the OCA pointed out that the DCF method has historically been the Commission's preferred method of setting common equity cost rates. I&E M.B. at 45; OCA M.B. at 59-60.

d. Recommended Decision

The ALJ agreed with I&E's proposal to calculate the recommended return on equity pursuant to the DCF methodology, using the CAPM as an alternate means to verify the reasonableness of the return on equity. The ALJ recommended the Commission approve the use of the DCF method as the primary method to determine the cost of common equity, consistent with the methodology commonly endorsed by the Commission in base rate proceedings. R.D. at 77-78.

e. Aqua Exception Nos. 1.1 and 1.4; OCA Exception No. 9 and Replies

In its Exception No. 1.1, Aqua contends that the ALJ erred by not analyzing the dividend yield and growth rate components of I&E's DCF methodology. Aqua claims I&E's use of spot prices, which were near the 52-week high of the proxy group, lowered its dividend yield. Aqua states that using only I&E's 52-week average dividend yield of 1.87% is very close to its own six-month average dividend yield of 1.94%. According to Aqua, I&E's growth rate is unreasonable because it improperly includes an extremely low growth rate of 3.6% for Middlesex Water. Citing *Columbia Gas*, Aqua notes that I&E excluded a high data point from its growth rate calculation on the basis that it was outside the norm and distorted the DCF results. If high growth rates can be excluded, as I&E has done in the past, then Aqua argues that low growth rates must also be excluded from I&E's DCF calculation. Aqua determines that removing the 3.6% growth rate for Middlesex Water from I&E's growth rate calculation results in a 7.74% growth rate. By adopting Aqua's dividend yield and calculating I&E's growth rate without Middlesex Water, the Company claims a DCF result of 9.68%. Aqua Exc. at 5-7.

In its Exception No. 1.4, Aqua maintains the ALJ inaccurately asserts that I&E used the DCF method and the CAPM method to arrive at its recommended ROE of 8.9%. Although I&E did prepare a CAPM analysis, Aqua states I&E ignored its 9.89% CAPM return on equity result. Aqua insists the Commission also recognizes the importance of informed judgment and information provided by other models. For example, Aqua submits that in the *2012 PPL Order,* the Commission considered the CAPM and RP methods instead of DCF-only results. Aqua claims one of the flaws of the DCF in a rising interest rate environment is that it lags in responding to interest rate changes. Therefore, Aqua proposes the CAPM and RP methods are necessary to consider in a time of rising interest rates because both methods directly reflect forecasts of interest rates and bond yields. In conclusion, Aqua argues that the ALJ's reliance upon I&E's DCF result should be rejected and the Commission should consider and reflect in its ROE determination the results of other methods more attuned to rising interest rates. Aqua Exc. at 10-12.

In its Replies to Aqua's Exceptions, I&E asserts that the ALJ correctly recognized that Commission precedent favors the use of the DCF methodology, as applied by I&E, and that Aqua's DCF calculation included the use of an inflated growth rate and an unnecessary leverage adjustment. According to I&E, Aqua has erroneously argued that I&E ignored its CAPM result in deriving the I&E ROE recommendation. I&E expresses that it uses the DCF method as the primary methodology to calculate its recommended return on equity while also using the CAPM as a check on the reasonableness of its DCF results. I&E R. Exc. at 2-4.

In its Replies to Aqua's Exceptions, the OCA submits that contrary to Aqua's assertion, the DCF growth rate recommended by the ALJ is not understated. The OCA avers Aqua's argument for increasing the Growth Rate to 7.5% based on excluding the Middlesex Water IBES/First Call growth rate should be denied. OCA R. Exc. at 5-10.

In its Exception No. 9, the OCA claims the ALJ erred by adopting I&E's DCF model. The OCA maintains its Quarterly Approximation DCF model is more reasonable than Aqua's and I&E's DCF calculations because it accounts for quarterly growth of dividends rather than annual growth. Additionally, the OCA argues its Quarterly Approximation DCF model produces higher cost of equity estimates compared with the other DCF Model variations because dividends are compounded quarterly. In estimating the growth rate, the OCA insists it is prudent for U.S. GDP to be a limiting factor for the long-term growth rate input of the DCF model. OCA Exc. at 12-14.

In its reply to the OCA's Exception No. 9, Aqua maintains the ALJ correctly rejected the OCA's DCF method. Aqua insists the OCA uses an arbitrary growth rate and its DCF method should be rejected. Aqua R. Exc. at 8.

In its reply to the OCA's Exception No. 9, I&E supports the ALJ's adoption of its methodology, resulting in an 8.90% ROE. I&E R. Exc. at 15.

f. Disposition

Upon our consideration of the record evidence, we agree with the ALJ's determination that Commission precedent prefers the DCF methodology as applied by I&E. We also are persuaded by the arguments of Aqua that the Commission recognizes the importance of informed judgment and information provided by other ROE models. Therefore, we shall deny Aqua's Exception No. 1.1 and the OCA's Exception No. 9, and grant Aqua's Exception No. 1.4, consistent with the following discussion.

Aqua suggests I&E's use of spot stock prices skewed its dividend yield lower, thus reducing the DCF ROE. However, the record does not include any testimony specifying how I&E may have erred by including spot stock prices when calculating the proxy group dividend yield. The Commission affirmed I&E's DCF methodology in *Columbia Gas* and *PECO Gas*, thereby verifying I&E's use of spot stock prices. We find that I&E's DCF proxy group dividend yield calculation appropriately includes spot stock prices.

Next, Aqua claims I&E's growth rate is low because it includes an unreasonable growth rate for Middlesex Water. Aqua submits that I&E excluded an unreasonable growth rate from a proxy group it used in *Columbia Gas* and should do the same in the instant case. As the OCA points out, the growth rate excluded in *Columbia Gas* was 26.5%, 3.5 times greater than I&E's *Columbia Gas* proxy group average growth rate. OCA R. Exc. 5-6. In the instant case, Middlesex Water's growth rate is 3.6% compared to I&E's proxy group average of 7.15%, less than half of the proxy group average. We do not find Middlesex Water's growth rate to be unreasonably low and, as such, it was appropriately included in I&E's DCF growth rate calculation.

The OCA claims the ALJ erred by not adopting its Quarterly Approximation DCF model. Like Aqua, we find the OCA's Quarterly Approximation DCF methodology to be unconventional and that it includes flaws with both its dividend yield and growth rate calculations. Aqua M.B. 126-128. Additionally, we find the OCA's Quarterly Approximation DCF methodology to be inconsistent with the DCF methodology affirmed in both *Columbia Gas* and *PECO Gas*. Therefore, we find the ALJ did not err by rejecting the OCA's Quarterly Approximation DCF methodology.

We are persuaded by the arguments of Aqua that the ALJ erred by concluding I&E used its DCF *and* CAPM results to determine Aqua's ROE. In this regard, we note that although I&E did use its CAPM as a comparison to its DCF result, it made no CAPM based adjustment to its final ROE recommendation. I&E M.B. at 47. As Aqua points out, *infra,* the U.S. economy is currently in a period of high inflation. To help control rising inflation, the Federal Open Market Committee has signaled that it is ending its policies designed to maintain low interest rates. Aqua Exc. at 9. Because the DCF model does not directly account for interest rates, consequently, it is slow to respond to interest rate changes. However, I&E's CAPM model uses forecasted yields on ten-year Treasury bonds, and accordingly, its methodology captures forward looking changes in interest rates.

Therefore, our methodology for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies. As noted above, the Commission recognizes the importance of informed judgment and information provided by other ROE models. In the *2012 PPL Order*, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination. In light of the above, we shall determine an appropriate ROE for Aqua using informed judgement based on I&E's DCF and CAPM methodologies.

Accordingly, we shall deny Aqua's Exception No. 1.1 and the OCA's Exception No. 9, and shall grant Aqua's Exception No. 1.4

2. Leverage Adjustment and Management Performance

a. Positions of the Parties

As previously noted, Aqua argued that a leverage adjustment should be added to its DCF cost rate. In addition, Aqua proposed to add a management effectiveness adjustment to its ROE claim. Both I&E and the OCA opposed the addition of a leverage adjustment or any allowance for management effectiveness.

As noted above, Aqua claimed that a utility that has a stock price above its book value and has an embedded cost of debt that is different from its marginal cost of debt has a market value or capitalization of its equity that is greater than the book value of its equity. Thus, Aqua explained, when an investor purchases equity at the market price (*i.e.,* the price used in the DCF model), the percentage of equity in the market capitalization is greater than the percentage of equity at book value. According to the

Company, under such circumstances, the DCF cost rate based on market prices must be adjusted upward to reflect the greater financial risk created by a higher debt ratio when that cost rate is applied to a book value capitalization in utility rate proceedings. Aqua M.B. at 113.

Aqua noted that the Commission has applied a leverage adjustment in cases in which it believes market conditions have resulted in an understated DCF cost rate. In support of this argument, Aqua cited to several previous rate cases before the Commission, including the *2004 PPL Order*, in which the Commission applied a leverage adjustment of forty-five basis points. Aqua M.B. at 112-13. Aqua further claimed that the Commonwealth Court has held that the decision of whether to adopt a leverage adjustment is within the Commission's discretion. *Id.* (citing *Popowsky v. Pa. PUC*, 868 A.2d 606, 612-13 (Pa. Cmwlth. 2004) (*2004 PA American*)).

According to Aqua, the market conditions that were present in the above rate cases also exist in this current proceeding. Aqua pointed to, *inter alia,* the high inflation rate that is currently present in the economy. Aqua reasoned that higher inflation expectations point to higher interest rates, which will contribute to higher capital costs prospectively, given that higher inflation results in greater risk of recovery of operating costs and greater volatility of earnings. In turn, Aqua insisted that the resulting increased capital costs warrant its requested leverage adjustment of 234 basis points. Aqua M.B. at 111, 117; Aqua St. 7 at 35.

As noted above, the Company also proffered that it demonstrated strong performance in the area of management effectiveness, such that it should be recognized by the Commission. Thus, Aqua sought an upward adjustment to its cost of equity for management effectiveness. Although the Company did not quantify what it believes to be an appropriate level of additional basis points for management performance,[62] it nonetheless claimed that in accordance with Section 523 of the Code, 66 Pa. C.S. § 523, the Commission is required to consider management effectiveness in setting a utility's rates. According to Aqua, nothing in Section 523 of the Code requires a finding that a utility must outperform all other utilities in the Commonwealth or that a utility's programs not be funded by customers before it is eligible for an increment to the rate of return for management performance. Aqua M.B. at 121, 128-29.

Aqua argued that it is committed to providing safe and reasonable service for the benefit of its communities and the environment. Aqua stated that it continues to assist the Commonwealth in dealing with the problems created by small, troubled, or non-viable water and wastewater systems. Aqua submitted that it provides high quality service and has implemented numerous programs designed to enhance the service it provides to customers. In support of these claims, Aqua highlighted that: (1) it maintains a strong, constant focus on water quality by providing filtration for all surface water sources and disinfection for all ground water sources, and by maintaining a central water quality laboratory in which it regularly takes water samples from its systems and responds promptly to water quality issues; (2) has acquired various water and wastewater systems that are in need of substantial improvement, has made larger scale plant upgrades that were beyond the capability of prior owners and/or operators, and has agreed to be a receiver for other troubled water systems under the provisions of Section 529 of the Code, 66 Pa. C.S. § 529; (3) has taken proactive measures to achieve its goal of providing twenty-four hour per day uninterrupted service to customers including undertaking extraordinary remediation and reconstruction efforts of the systems it has undertaken as a

[62] While Aqua did not quantify what it believes to be an appropriate amount of additional basis points for management effectiveness, it did highlight that the Commission awarded the Company an upward adjustment of twenty-two basis points for management effectiveness in *Pa. PUC v. Aqua Pa., Inc.*, Docket No. R-00072711 (Order entered July 31, 2008) (*2008 Aqua Order*). Aqua M.B. at 115.

receiver; (4) seeks to contain operating costs by reviewing staffing needs and operating procedures to reduce operating expenses and by proactively taking advantage of refinancing opportunities and lowered interest rates on long-term debt; (5) has leveraged its size and operational abilities to develop rates that are just and reasonable, while also prudently investing in needed capital in the utility infrastructure serving its customers; (6) has successfully provided its water and wastewater services during the COVID-19 pandemic without any interruption, while furnishing a safe workplace for its essential employees; (7) has proactively implemented changes to its low-income program, and policies to help customers who have been impacted by the pandemic, including providing credits to its low-income customers; (8) has assisted other water and wastewater systems during the pandemic; (9) has provided its customers with a high level of customer service, including rolling out technology designed to improve customers' ability to be advised of, and track service disruptions; (10) has maintained its "A Helping Hand" low-income customer assistance program to help facilitate the payment of water bills by its low-income residential customers; (11) continues to embark on substantial capital programs intended to ensure long-term viability by rehabilitating its underground piping infrastructure; (12) has taken advantage of key tax programs to ensure the lowest possible cost of service for its customers; and (13) has taken environmental initiatives, including seeking to minimize its purchased power costs and to improve its carbon footprint to ensure that it is being a good steward of the environment. Aqua M.B. at 129-37.

In contrast, I&E recommended that the Commission reject both the Company's request for a leverage adjustment and its request for a management performance adjustment. With regard to the Company's proposed leverage adjustment, I&E took the position that the Company's proposal was inappropriate for several reasons. First, I&E claimed that the Company's proposal is not supported by academic journals, textbooks, or other literature, and that rating agencies assess financial risk based upon a company's financial statements, and not its market capital structure. Second, I&E cited to several recent rate cases to illustrate that Commission precedent favors rejecting a utility's request for a leverage adjustment. Third, I&E posited that a leverage adjustment would unduly burden the Company's ratepayers. In this regard, I&E claimed that awarding the Company a leverage adjustment of 234 basis points would cause Aqua's ratepayers to fund an additional amount of $68,578,855 annually to cover the increase of an inflated rate of return along with the associated impact resulting from increases to income taxes, gross receipts tax, uncollectibles, and assessments. I&E M.B. at 51-54.

As to the Company's request for an upward adjustment in recognition of management effectiveness, I&E likewise contended that no such adjustment is warranted. In this regard, I&E provided that the true measure of whether a utility has exhibited strong management performance is whether the utility earns a higher return through the efficient use of resources and cost cutting measures. I&E continued that the increased income resulting from cost savings and true efficiency in management and operations is to be passed on to shareholders. I&E opined that the initiatives the Company cited to in support of its request for a management effectiveness adjustment demonstrate nothing more than the Company meeting the requirements outlined in Section 1501 of the Code, 66 Pa. C.S. § 1501, that it must provide adequate, efficient, safe, and reasonable service. In I&E's view, neither Aqua, nor any other utility should be awarded additional basis points to their ROE for simply meeting the requirements set forth in Section 1501. I&E M.B. at 47-48.

I&E also submitted that if the Company is as effective at controlling operating and maintenance costs as it argues, those savings should flow through to its ratepayers and/or investors. At the same time, I&E contended that Aqua's claimed savings to its ratepayers would likely be offset by the addition of basis points for management performance, as ratepayers would have to fund the additional costs. I&E reasoned that this would defeat the purpose of cutting expenses to benefit ratepayers. I&E M.B. at 49-50. Further, I&E cited to *Columbia Gas* wherein the Commission upheld the finding of ALJ Katrina L. Dunderdale that Columbia's management performance adjustment should be denied in light of the ongoing COVID-19 pandemic, noting that Columbia's proposal would defeat the purpose of cutting expenses to benefit ratepayers, particularly during a period in which many ratepayers have experienced reduced income from job loss or reduction in hours. *Id.* at 50 (citing *Columbia Gas* at 134). I&E posits that the Commission should reach a similar conclusion in this current proceeding. I&E M.B. at 50.

The OCA echoed the position of I&E that neither the Company's proposed leverage adjustment nor its proposed management effectiveness adjustment should be granted. The OCA acknowledged Aqua's statement that, as set forth in the Commonwealth Court's decision in *2004 PA American*, the decision of whether to adopt a leverage adjustment is within the Commission's discretion and is made on a case-by-case basis. OCA M.B. at 66. However, the OCA averred, *inter alia,* that the Commission typically only applies a leverage adjustment in cases in which market conditions have resulted in a DCF cost rate that is understated. *Id.* (citing *2012 PPL Order* at 120). The OCA opined that the opposite conditions exist in this current proceeding such that any leverage adjustment would be unnecessary and would be contrary to the public interest. OCA M.B. at 66-67.

According to the OCA, the primary reason for Aqua's inclusion of a leverage adjustment is that it seeks a higher return on equity than what the record supports. The OCA submits that although the Company cited the prospect of risks to investors, the Company failed to note that as a public utility operating in a monopoly environment, it faces less risk than the average company, which operates in a competitive marketplace. In addition, the OCA argued that in citing the potential risks to its investors, Aqua failed to acknowledge the additional risks that would be imposed on its ratepayers if it were awarded a leverage adjustment. Thus, the OCA claimed that the Company's request should be disregarded by the Commission. OCA M.B. at 67-68; OCA R.B. at 31-33.

Likewise, the OCA argued that the Company's request for an upward adjustment to its ROE for management performance is wholly unsupported. According to the OCA, Aqua has not conducted any comparative analyses to determine if the Company's management performance is superior to that of other regulated utilities, including those in its proxy group. To the contrary, the OCA claimed that the record thoroughly demonstrates that Aqua's management has not performed effectively in a variety of metrics, including but not limited to water quality, wastewater treatment compliance, system reliability, cost containment, rates, COVID-19 response, customer service, low-income customer assistance programs, infrastructure rehabilitation, tax programs, and environmental initiatives. As such, the OCA claimed that there is no basis for awarding a rate of return higher than Aqua's estimated cost of equity. OCA M.B. at 75-76; OCA R.B. at 34-35.

b. Recommended Decision

The ALJ concluded that Aqua has failed to justify that the addition of a leverage adjustment to its DCF cost calculation would be appropriate. Thus, the ALJ recommended that the Company's proposed leverage adjustment of 234 basis points be denied. R.D. at 78-79.

The ALJ also concurred with the positions of I&E and the OCA that Aqua should not be awarded any upward adjustment for strong management performance. First, the ALJ found that although it is true that the Company has been a strong partner with the Commission in acquiring troubled water systems, it has also acquired water and wastewater systems that were not troubled and has asked its existing customer base to help finance the costs to serve its newly acquired customers through base rates, reconcilable surcharge mechanisms, and/or its Distribution System Improvement Charge (DSIC). Thus, the ALJ concluded that the Company's claimed savings to ratepayers would likely be offset by the addition of basis points for management performance, as ratepayers would need to fund the additional costs. In the ALJ's view, this would defeat the purpose of cutting expenses to benefit ratepayers. R.D. at 79-80.

Next, the ALJ concluded that although the Commission has rejected the notion that no rate increases are appropriate during the COVID-19 pandemic, it is also not appropriate to demand more from ratepayers than necessary to meet the utility's basic needs. The ALJ pointed out that at the public input hearings many of Aqua's customers described the additional economic burdens caused by job loss, elevated family care responsibilities and other hardships resulting from the ongoing effects of the pandemic. According to the ALJ, to permit the Company to seek an additional premium from ratepayers during a pandemic would be inequitable and "tone deaf" given the high level of unemployment experienced by residential customers and the detrimental effect the pandemic has had on small businesses. Thus, the ALJ concurred with I&E that the Commission should apply the same reasoning set forth in *Columbia Gas, supra,* and should deny the Company's request to add basis points to its ROE for strong management performance. R.D. at 80-81.

c. Aqua Exception Nos. 1.2 and 1.6 and Replies

In its Exception No. 1.2, Aqua finds fault with the ALJ's recommendation that the Company's proposed leverage adjustment should be rejected. The Company contends that the ALJ has failed to consider that the Commission has included an adjustment for leverage in instances where the DCF understates the cost of common equity. Aqua insists that such conditions are present in this instant proceeding. Aqua restates its arguments, *supra,* that a leverage adjustment is designed to adjust the DCF cost rate for the different percentage of debt in the capital structure calculated at market values of equity and long-term debt, as compared to the percentage of debt in the capital structure at book value, and to align those risks. Aqua Exc. at 7.

Next, Aqua acknowledges that the Commission has been selective in awarding a leverage adjustment to the DCF cost calculation in rate cases. However, Aqua submits that what is most apparent from the decisions in which the Commission has not adopted a leverage adjustment is that the Commission has concluded that the unadjusted DCF results in such cases do not underestimate the cost of common equity. According to the Company, there is substantial evidence in this instant proceeding to demonstrate that the unadjusted DCF results understate the cost of common equity in the current environment. Thus, Aqua submits that the Commission should reverse the ALJ's recommendation and should award the company a leverage adjustment of 234 basis points, or 2.34%. Aqua Exc. at 7-8.

In its Exception No. 1.6, Aqua claims that in recommending that the Commission reject the Company's request for an upward adjustment to its ROE for strong management performance, the ALJ has disregarded the requirements of Section 523 of the Code, 66 Pa. C.S § 523. Aqua notes that Section 523 directs the Commission to consider the efficiency, effectiveness, and adequacy of service of each utility when determining just and reasonable rates. Aqua argues that while the ALJ concluded that providing additional basis points for effective management may offset cost savings such that it would defeat the purpose of cutting expenses to benefit ratepayers, the Commission has rejected contentions that utilities should not be provided additional basis points for quality utility service in light of Section 523. Aqua insists that the Commission should similarly reject such contentions in this proceeding. Aqua Exc. at 13-14.

Aqua also objects to the ALJ's finding that while the Company has been a strong partner with the Commission in acquiring troubled water systems, it has also acquired systems that were not troubled and has asked existing customers to pay for those acquisitions. Aqua claims that such acquisitions are mutually exclusive. The Company avers that it includes in rate base only those amounts permitted by law. In addition, Aqua insists that cost savings for its ratepayers have been realized through economies of scale associated with its acquisitions. Thus, Aqua submits that incentives to encourage acquisitions and regionalization to reduce the number of troubled water systems in the Commonwealth should not be denied simply because the Company also undertakes acquisitions of some entities that may not be classified as "troubled." Aqua Exc. at 14.

In its Replies to the Exceptions, I&E counters that the ALJ correctly rejected Aqua's proposed leverage adjustment. I&E maintains that Aqua has erroneously argued that there is substantial evidence to demonstrate that the unadjusted DCF results understate the cost of common equity in the current economic environment and that the ALJ appropriately rejected these arguments. I&E R. Exc. at 2.

In a similar fashion, I&E submits that the ALJ properly denied the Company's request for an upward adjustment to its ROE for strong management performance. I&E refutes Aqua's contention that the ALJ disregarded the requirements of Section 523 of the Code. To the contrary, I&E asserts that the ALJ properly considered the record evidence and the arguments presented by all of the Parties and then concluded that awarding the Company a management effectiveness adjustment is not warranted in this proceeding. I&E remains of the opinion that the Commission should reject the Company's request, consistent with its reasoning for rejecting a management performance adjustment in *Columbia Gas.* I&E R. Exc. at 5-6.

The OCA's arguments in its Replies to Exceptions mirror those of I&E with regard to both the leverage adjustment and the management performance adjustment. As to the leverage adjustment, the OCA also adds that the unadjusted DCF results of Aqua, I&E, and the OCA all fall between 8% and 9.07%, indicating a relatively small range resulting from the application of DCF models employed by the Parties' respective expert witnesses. Thus, the OCA submits that the Company's 234 basis point adjustment is unreasonable and creates substantial burdens for consumer ratepayers as subsidizers of investors. In addition, the OCA claims that the Company incorrectly posited that the market-derived cost of equity needs to be adjusted to compensate for the difference in financial risk. The OCA restates its argument that because Aqua is a regulated public utility, it does not have greater financial risk when compared to the average company in the competitive marketplace. OCA R. Exc. at 6-8.

Furthermore, the OCA highlights that the Commission has routinely denied proposed leverage adjustments in rate case proceedings. In the OCA's view, the record evidence in this current proceeding does not support Aqua's request for a leverage adjustment and the ALJ appropriately rejected the Company's request. OCA R. Exc. at 7-8.

As to the Company's Exception No. 1.6, the OCA restates its position that Aqua has been *deficient* in many areas of management performance.[63] The OCA submits that even absent these deficiencies, the provision of safe, adequate, and reliable water and wastewater service is required under Section 1501 of the Code, 66 Pa. C.S. § 1501. As a result, the OCA asseverates that simply meeting these required standards does not constitute exemplary management performance. Otherwise, the OCA reasons, the Commission would be awarding unwarranted additional basis points for management effectiveness to nearly every utility under its jurisdiction. OCA R. Exc. at 8-9.

The OCA also refutes the Company's claim that its acquisition of small, troubled, or non-viable wastewater systems warrants consideration for additional basis points for strong management performance. The OCA points to the ALJ's finding that

[63] As discussed in Section XII.A, *infra,* the OCA, in its Exception No. 23, argues that Aqua's customer satisfaction survey, which indicates that only seventy-three percent of its customers rated their satisfaction as "excellent" or "very good" lends further support for rejecting the Company's request for a management effectiveness adjustment. *See* OCA Exc. at 34-35.

the costs of rehabilitating these systems is passed along to the Company's other ratepayers. According to the OCA, even if the Company's reference to economies of scale proves true, this is not an indicator of effective management performance. Instead, the OCA maintains that such economies are a function of the Company's system. Thus, the OCA asserts that the ALJ properly rejected the Company's request for an upward adjustment to its ROE for management performance. OCA R. Exc. at 9-10.

d. Disposition

As Aqua correctly notes in its Exception No 1.2, the Commission has been selective in adding a leverage adjustment to the DCF cost calculation in rate cases. We reinforced this in *UGI Electric*, stating that "the fact that we have granted leverage adjustments in a few select cases in the past does not mean that such adjustments are warranted in all cases. Rather, the award of such an adjustment is not precedential but discretionary with the Commission." *UGI Electric* at 93; *see also 2012 PPL Order* at 91.

In examining the record in this proceeding, we are not persuaded by Aqua's arguments that we should reach a different conclusion from that reached in *UGI Electric* and other recent base rate proceedings and award the Company an artificial leverage adjustment to its ROE. In its briefs, Aqua cited to the high inflation rate that is currently present in the economy in support of its argument for a leverage adjustment. Aqua M.B. at 117. However, the crux of the Company's request for a leverage adjustment to its ROE centers on its belief that the difference between its book value capital structure and its market value capital structure poses a financial risk. Thus, the Company seeks a leverage adjustment to account for applying the market value cost rate of equity to the book value of its equity.

We find I&E's arguments in opposition to the Company's position to be persuasive. For example, as I&E observed, credit rating agencies assess financial risk based upon a company's booked debt obligations and the ability of its cash flow to cover the interest payments on those obligations. The agencies use a company's financial statements, and not the company's market capital structure, in conducting their analysis. It is a company's financial statements that affect the market value of the stock, and, therefore, the financial statements and the book value capital structure are relied upon in an analysis such as that done by rating agencies. I&E St. 2 at 40; I&E St. 2-SR at 10. Accordingly, we find that the record in this proceeding supports rejecting the Company's requested leverage adjustment.

Additionally, we note that PPL, in its 2012 rate case, sought a leverage adjustment in the range of 70 to 118 basis points based upon similar arguments regarding a perceived risk related to its market to book ratio. Likewise, UGI Electric, in its 2018 rate case, sought a leverage adjustment on this same basis. We found no merit in these arguments. *2012 PPL Order* at 91; *UGI Electric* at 93. We likewise find no merit in Aqua's arguments in which it seeks to support a leverage adjustment that is more than 100 basis points higher than that requested by either PPL or UGI Electric. Rather, we find, as we did in those base rate proceedings, that awarding the Company a leverage adjustment would run contrary to the public interest. Therefore, we shall deny the Company's Exception No. 1.2.

As to the Company's requested management performance adjustment, we note that pursuant to the Code, the Commission may reward utilities through rates for their performance. In pertinent part, Section 523 of the Code, 66 Pa. C.S. § 523, provides:

> **§ 523. Performance factor consideration.**
>
> (a) **Considerations.** – The Commission shall consider, in addition to all other relevant evidence of record, the efficiency, effectiveness and adequacy of service of each utility when determining just and reasonable rates under this

title. On the basis of the commission's consideration of such evidence, it shall give effect to this section by making such adjustments to specific components of the utility's claimed cost of service as it may determine to be proper and appropriate. Any adjustment made under this section shall be made on the basis of specific findings upon evidence of record, which findings shall be set forth explicitly, together with their underlying rationale, in the final order of the commission.

(b) **Fixed utilities.** – As part of its duties pursuant to subsection (a), the commission shall set forth criteria by which it will evaluate future fixed utility performance and in assessing the performance of a fixed utility pursuant to subsection (a), the commission shall consider specifically the following:

(1) Management effectiveness and operating efficiency as measured by an audit pursuant to Section 516 (relating to audits of certain utilities) to the extent that the audit or portions of the audit have been properly introduced by a party into the record of the proceeding in accordance with applicable rules of evidence and procedure.

* * *

(4) Action or failure to act to encourage development of cost-effective energy supply alternatives such as conservation or load management, cogeneration or small power production for electric and gas utilities.

* * *

(7) Any other relevant and material evidence of efficiency, effectiveness and adequacy of service.

On consideration of the record evidence in this proceeding, we shall award Aqua an upward adjustment of twenty-five basis points to its ROE for management effectiveness, consistent with the following discussion.

We specifically recognize Aqua's efforts and willingness to quickly provide emergency aid to various water and wastewater systems that needed substantial improvement. Aqua has often provided this emergency aid on short notice and at the request of the Commission or other parties to protect the public from egregious health and safety threats and to protect the Commonwealth's drinking water resources from catastrophic damage. The competence and reliability of Aqua's management effectiveness in this regard is unparalleled. Aqua's management has earned this reputation by consistently and successfully working to protect the public and the environment under emergency situations presenting highly difficult operational, financial, and legal issues over many years. For example, we note the aid rendered by Aqua in Emlenton, Pennsylvania where the Commission fielded approximately ninety-three simultaneously filed formal complaints against the Emlenton Water Company alleging unsafe and inadequate water service and water-born illness. *See Bradley Louise, et al. v. Emlenton Water Company*, Docket No. C-2008-2058411 (Complaint filed July 24, 2008); *Joint Application of Aqua Pennsylvania, Inc. and Emlenton Water Company*, Docket No. A-2008-2074746 (Order entered December 29, 2008).

Aqua's management performance in recent emergency situations reinforces that the Company has been, and continues to be, a trusted and reliable corporate citizen on which the public can rely. Specifically, Aqua is currently operating three troubled utility systems under emergency receiverships throughout the Commonwealth, including one wastewater and two water systems. These respectively include North Heidelberg Sewer Company (NHSC), Twin Lakes Utilities, Inc. (Twin Lakes), and James Black Water Service Company (James Black). *See* Aqua St. 1 at 40; Aqua M.B. at 133-34.

Regarding NHSC, on March 21, 2017, I&E requested that the Commission issue an *Ex Parte* Emergency Order to avoid "a tidal wave of adverse consequences, including the potential discharge of untreated wastewater into the Commonwealth's waterways, which could result in irreparable harm to the environment, the health of NHSC's customers, and the safety of the public at large." *See Pa. PUC v. Metropolitan Edison Company and North Heidelberg Sewer Company*, Docket No. P-2017-2594688, (Petition for *Ex Parte* Emergency Order filed March 21, 2017) at 11.[64] At that time, NHSC served approximately 273 residential and one commercial wastewater customer. *May 2017 Order* at 5. I&E added that should NHSC fail to immediately take corrective action, the Commission should appoint a receiver pursuant to 66 Pa. C.S. § 529 because it appeared that NHSC was "consciously and intentionally placing in jeopardy its ability to provide safe, reliable and reasonable wastewater service to its customers." Petition for *Ex Parte* Emergency Order at 12. In the *Ex Parte* Order, Chairman Dutrieuille directed Aqua to assume this receiver role, which Aqua immediately and willingly did.

This past autumn, Hurricane Ida substantially destroyed NHSC's wastewater treatment plant and Aqua immediately responded to avert what could have been yet another disaster to the environment and to downstream drinking water supplies. Aqua M.B. at 131. Aqua's reconstruction efforts have gone beyond the normal expectations of a receiver. *Id.* On May 2, 2022, Aqua filed its 17th quarterly status report regarding its successful and ongoing five-year effort to rehabilitate the NHSC system, both operationally and financially, for the safety and benefit of the families served by that system and all Commonwealth residents downstream of its wastewater discharge. In our view, Aqua's reconstruction efforts have gone beyond the normal expectations of a receiver.

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[64] On March 22, 2017, Chairman Gladys Brown Dutrieuille signed an *Ex Parte* Emergency Order (*Ex Parte* Order) granting the Petition for *Ex Parte* Emergency Order as modified to ensure continued wastewater service from NHSC to its customers, subject to ratification by the full Commission. On April 6, 2017, the Commission issued a Ratification Order of the *Ex Parte* Order. Subsequently, the Commission modified the *Ex Parte* Emergency Order. *Pa. PUC v. Metropolitan Edison Company and North Heidelberg Sewer Company*, Docket No. P-2017-2594688 (Order entered May 4, 2017) (*May 2017 Order*).

Regarding Twin Lakes, on October 23, 2018, Twin Lakes petitioned the Commission to approve an abandonment of water service to its approximately 114 residential customers no later than March 31, 2019. *Twin Lakes Utilities, Inc. Application to Abandon Service to its customers in Sagamore Estates in Shohola Township, Pike County Pennsylvania*, Docket No. A-2018-3005590 (filed October 23, 2018). Twin Lakes claimed it could no longer provide service to its customers because of significant quality of service and financial issues. *Id.*; *see also*, *Office of Consumer Advocate's Answer in Support of the Petition of Twin Lakes Utilities*, Docket No. P-2020-3020914 (filed August 5, 2020) (also containing a reiteration of the history and issues behind the Twin Lakes Section 529 forced acquisition petition supported by the OCA).

On June 10, 2020, Twin Lakes provided notice to the Commission that on September 1, 2020, it would cease providing water service to its customers. *Twin Lakes Utilities, Inc. – Notice of Termination of Service Agreement Between Middlesex Water Company and Twin Lakes Utilities, Inc.*, Docket No. M-2020-3020390 (served June 10, 2020). The practical effect of such abandonment would be the loss of potable water service and, for many customers, the loss of water for in-home sanitation as well. On July 13, 2020, the Commission directed that Twin Lakes "shall not abandon or surrender water service to its customers, in whole or in part, without Commission authorization." *Twin Lakes Utilities, Inc. – Notice of Termination of Service Agreement Between Middlesex Water Company and Twin Lakes Utilities, Inc.*, Docket No. M-2020-3020390 (*Secretarial Letter* issued July 13, 2020.)

Nevertheless, on August 3, 2020, Twin Lakes provided public notice to its customers that "to protect the public health, Twin Lakes will cease water service at 12:01 am on September 1, 2020." *Twin Lakes Utilities, Inc. Section 529 Petition*, Docket No. P-2020-3020914 (filed August 3, 2020.) Shortly thereafter, the OCA petitioned the

Commission stating that the "OCA respectfully requests the Commission direct Aqua Pennsylvania to act as a receiver to operate Twin Lakes until the resolution of the Section 529 proceeding." *Office of Consumer Advocate Petition for Issuance of an Interim Emergency Order on an Expedited Basis*, Docket No. P-2020-3020914 (filed August 18, 2020) at ¶ 18. The OCA opined that "Aqua Pennsylvania appears to be financially, managerially, and technically capable to serve Twin Lakes' customers. It is a capable PUC jurisdictional water utility and a proximate public utility as required under Section 529." *Id*. at ¶ 17 (*citations omitted*). We note that Aqua willingly took on this request and the Company continues to make significant investments into the Twin Lakes system to ensure its customers receive safe water service.

Simultaneous with its work with NHSC and Twin Lakes, Aqua is also serving as a receiver to James Black, a typical small, troubled water system with approximately nineteen customers. *See In re James Black Water Service Company*, Docket No. M-2019-3012563 (*Ex Parte* Emergency Order issued September 3, 2019; Order ratified September 19, 2019). We include a description of this typical small troubled water system only to provide perspective on the difference in scale required to rehabilitate NHSC and Twin Lakes, and to comment on the depth of resources, expertise, and employee commitment required to simultaneously manage all these emergency efforts, as the Company has done.

In view of the above, it is clear that Aqua has answered the call to provide emergency assistance at the request of the public, public advocates, and government agencies. Given the nature and frequency of these emergencies, we are of the opinion that the Company should be recognized for its efforts to serve as a ready and willing ally in water and wastewater emergencies. In our view, affording Aqua a modest upward adjustment to its ROE to recognize its exemplary emergency service is a just, reasonable, and affordable approach to addressing its ongoing emergency aid efforts. It would be inequitable to proceed otherwise, as there is no provision of the Code that demands utilities exhaust employees or financial resources because of emergencies occasioned by others.

Section 523 of Code, *supra,* permits the Commission to award a management performance adjustment based on "[a]ny other relevant and material evidence of efficiency, effectiveness and adequacy of service." 66 Pa. C.S. § 523(b)(7). Aqua's consistent willingness to answer calls for aid to other water and wastewater providers shows it is doing more than required under Section 1501 of the Code. The examples discussed above indicate that Aqua carries a roster of large and complex emergency aid matters unlike any other Pennsylvania utility. As stated in its direct testimony, operating troubled systems requires significant time, commitment, and involvement from many departments within Aqua. Aqua St. 1 at 20. As such, Aqua management is exceeding the expectations placed upon it not only by its existing customers, but also the Commonwealth. For this reason, we find that Aqua should receive a management efficiency award commensurate with the emergency service described herein. Therefore, to reflect the extraordinary effort exhibited by Aqua to aid and protect Pennsylvania water and wastewater customers and the environment, we shall award Aqua an additional twenty-five basis points to its ROE for management performance. As discussed in Section X.D.3, *infra,* this will result in a total ROE for the Company of 10.00%.[65] Accordingly, we shall grant Aqua's Exception No. 1.6.

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[65] As previously noted, in the *2008 Aqua Order,* the Commission awarded Aqua a management performance adjustment of twenty-two basis points for a total ROE of 11.00%.

3. Rate of Return on Common Equity

a. Positions of the Parties

As noted above, four methods of determining the cost of equity were presented for inclusion in the record in this proceeding: (1) DCF; (2) CAPM; (3) RP; and (4) CE. Aqua relied on each of these methodologies in presenting its recommended rate of return on common equity of 10.75%. Aqua St. 7 at 7.

As previously discussed, both I&E and the OCA took issue with the Company's analysis in arriving at the proposed cost of equity and argued that equal weight should not be given to the four different methodologies as Aqua did in its evaluation. Additionally, both I&E and the OCA submitted that the Commission has indicated a preference for using the DCF method to establish reasonable common equity costs.

As a result of its DCF analysis, I&E recommended a cost of common equity of 8.90%. St. 2 at 21.

The OCA recommended a cost of common equity of 8.00% based on its DCF model. OCA St. 3 at 3.

b. Recommended Decision

The ALJ rejected Aqua's proposed rate of return on common equity of 10.75%. Namely, the ALJ agreed with I&E's proposal to calculate the recommended cost of equity pursuant to the DCF methodology and using the CAPM to verify the reasonableness of the DCF ROE. According to the ALJ, I&E's analysis is consistent with the methodology commonly endorsed by the Commission and most recently accepted in *Columbia Gas*. Therefore, the ALJ recommended that the Commission adopt the 8.90% cost of equity as determined by I&E. R.D. at 78.

c. Exceptions and Replies

(1) Aqua Exc. Nos. 1.3, 1.5, and 1.7 and Replies

In its Exception Nos. 1.3 and 1.7, Aqua disagrees with the ALJ's cost of equity recommendation of 8.90%, based on I&E's methodology recently approved in *Columbia Gas*. Aqua takes the position that

> "[i]f adopted, this ROE will represent a watershed moment for the end of the Commission's longstanding commitment to supporting infrastructure investment, made doubly worse in a period of rising capital costs. The RD ROE would signal to the utilities and the credit rating agencies that Pennsylvania regulation has ceased to support investment in the state at a time of critical capital investment needs."

Aqua claims the ALJ erred by using a formulaic application of I&E's DCF method. In selecting I&E's recommended ROE, Aqua asserts the ALJ is implicitly endorsing an approach that rejects the application of informed judgment. In further support of its position, Aqua argues that the ALJ completely failed to address the substantial increases to the rate of inflation that have been experienced subsequent to the preparation of rate of return recommendations by the Parties. Aqua highlights that the inflation rate reported in December of 2021 was a thirty-nine year high of 6.8%. Aqua adds this current period of significant inflation "shows no signs of abating." Aqua Exc. at 2-4, 9-10, 13.

In its Exception No. 1.5, Aqua stresses that the ALJ's recommendation of an 8.90% ROE is below recent Commission determinations of a 9.86% ROE for

Columbia Gas, and a 10.24% ROE for *PECO*. In addition, Aqua argues that the allowed DSIC ROE of 9.80% is further evidence that the ALJ's recommended 8.90% ROE is deficient and will not provide Aqua with the opportunity to earn its investor-required cost of capital for the FPFTY. Aqua reinforces its position that the Commission should not be reducing a utility's ROE when there is a continuing, compelling need for capital investment to rehabilitate aging infrastructure. Aqua Exc. at 12-13.

In its reply to Aqua's Exceptions, I&E disputes Aqua's argument that the ALJ's rate of return recommendation in this proceeding should have been based on the allowable DSIC rate of return and the rate of return awarded to other dissimilar public utilities in other base rate proceedings. Rather, I&E avers that the ALJ correctly considered the substantial record evidence presented by all Parties in this base rate proceeding and properly recommended the Commission adopt the I&E recommended 8.90% ROE. Aqua R. Exc. at 11-12.

In its reply to Aqua's Exceptions, the OCA submits that the ALJ correctly rejected Aqua's cost of equity recommendation of 10.75%. The OCA avers Aqua's proposed 10.75% ROE relies on flawed empirical analyses and unsupported upward adjustments. OCA R. Exc. at 5.

(2) OCA Exception No. 9 and Replies

In its Exception No. 9., the OCA claims the ALJ erred by adopting I&E's proposed ROE of 8.90%. The OCA believes that adoption of I&E's cost of equity recommendation, albeit more reasonable than Aqua's ROE calculation, still overstates the cost of common equity. The OCA remains of the opinion that a ROE of 8.0% should be awarded to the Company, based on its Quarterly Approximation DCF model. OCA Exc. at 12.

In its reply to the OCA's Exception No. 9, Aqua submits the OCA's proposed ROE should be rejected because it would signal to Pennsylvania utilities and the investment community that Pennsylvania regulation no longer is supportive of capital investment, made doubly bad given the clear rise in inflation and capital costs that are occurring. Aqua R. Exc. at 7-8.

In its reply to the OCA's Exception No. 9, I&E supports the ALJ's recommendation to adopt the methodology employed by I&E, which resulted in an 8.90% ROE, as the most reasonable. I&E R. Exc. at 15.

d. Disposition

As determined in our disposition of Sections X.D.1 and X.D.2, *supra*, we will rely upon I&E's DCF and CAPM methodology and informed judgment, in addition to awarding an upward adjustment of twenty-five basis points for management effectiveness, in arriving at our determination of the proper ROE to award to Aqua in this proceeding. In particular, we note that the evidence presented in this case based on I&E's CAPM methodology produced a ROE higher than the results produced by its DCF. This suggests that, while properly computed in the abstract, I&E's DCF results understate the current cost of equity for Aqua and that consideration should be given to the CAPM in determining the appropriate range of reasonableness.

We agree with Aqua that the setting of the proper return on equity is necessary in this environment of increasing inflation, leading to an increase in interest rates and capital costs. Aqua Exc. at 2-4, 9-10, 13. However, we disagree with Aqua benchmarking recent Commission ROE determinations for *Columbia Gas* and *PECO Gas*, in addition to the most recent DSIC ROE, as further evidence that the ALJ's recommended 8.90% ROE is deficient. We agree with I&E that *Columbia Gas* and *PECO Gas* are dissimilar public utilities to Aqua, and each had a company specific ROE determined by evidence presented at the time of its individual base rate case. Further, we note the DSIC ROE is unlike a ROE set in a base rate proceeding. The DSIC ROE is determined by the Commission on a quarterly basis and is set per industry. As such, it is not company specific. Therefore, we shall grant Aqua Exception Nos. 1.3 and 1.7 and deny Aqua Exception No. 1.5.

As also explained in our disposition of Section X.D.1, we found the ALJ did not err by rejecting the OCA's Quarterly Approximation DCF methodology. Consequently, we do not agree with the OCA's resultant 8.0% ROE for Aqua. Consistent with these determinations, we shall deny OCA Exception No. 9.

We have previously determined, above, that we shall utilize I&E's DCF and CAPM methodologies. I&E's DCF and CAPM produce a range of reasonableness for the ROE in this proceeding from 8.90% to 9.89%. Based upon our informed judgment, which includes consideration of a variety of factors, including increasing inflation leading to increases in interest rates and capital costs since the rate filing, we determine that a base ROE of 9.75% is reasonable and appropriate for Aqua. When combined with our upward adjustment of 25 basis points to the Company's ROE for management effectiveness, this will produce a final authorized ROE for Aqua of 10.00% (*i.e.*, 9.75% + 0.25% = 10.00%). Accordingly, we shall modify the ALJ's ruling as to the ROE to award Aqua in this proceeding.

E. Overall Rate of Return

1. Positions of the Parties

In this proceeding, Aqua claimed that it should be permitted to earn an overall rate of return of 7.64%. Aqua's proposed overall rate of return is comprised of a weighted average of a 4.00% rate of return on long-term debt, and a 10.75% rate of return on common equity, inclusive of an upward adjustment for management effectiveness. This is, in turn, based on a capital structure of 53.95% common equity and 46.05% long-term debt. Aqua Exh. 4-A at 1, Sch. 1.

I&E recommended that Aqua should be afforded the opportunity to earn an overall rate of return of 6.64%. This recommended overall rate of return is comprised of a weighted average of a 4.00% rate of return on long-term debt and an 8.90% rate of return on common equity and is based off of the Company's proposed capital structure. I&E M.B. at 42.

The OCA proffered that the Commission should allow Aqua the opportunity to earn a 6.00% overall rate of return on its rate base. The OCA's recommendation is comprised of a weighted average of a 4.00% rate of return on long-term debt and an 8.00% rate of return on equity and is based on a hypothetical capital structure of 50% common equity and 50% long-term debt. OCA M.B. at 53.

Although CAUSE-PA did not propose a specific rate of return for the Company in this proceeding, it stated that it supported and adopted the position of the OCA. CAUSE-PA M.B. at 12.

2. Recommended Decision

The ALJ recommended that the Commission adopt I&E's proposed overall rate of return of 6.64%. This is based upon the ALJ's recommendations, *supra*,: (1) approving the Company's proposed capital structure of 53.95% common equity and 46.05% long-term debt; (2) approving the Company's claimed cost rate of 4.00% for long-term debt; (3) utilizing I&E's methodology for determining a rate of return on common equity; and (4) denying the Company's claimed 234-basis point leverage adjustment and its upward adjustment for superior management performance. The ALJ's recommended rate of return is outlined in Table 6, as follows:

Type of Capital	Ratio	Cost Rate	Weighted Cost
Long-Term Debt	46.05%	4.00%	1.84%
Common Equity	53.95%	8.90%	4.80%
Total	100.00%		6.64%

Table 6: The ALJ's Recommended Capital Structure and Overall Rate of Return for Aqua

The ALJ applied this rate of return to Table IA of each of the rate tables set forth in the Appendix to the Recommended Decision. According to the ALJ, an overall rate of return of approximately 6.64% fairly balances the requirement that a utility be permitted an opportunity to recover those costs prudently incurred by all classes of capital used to finance the rate base during the prospective period in which its rates will be in effect, while also mitigating the revenue increases that will impact ratepayers who continue to struggle in the aftermath of the COVID-19 pandemic. R.D. at 81, Appendix Tables IA.

3. Exceptions and Replies

Only Aqua and the OCA filed exceptions to the ALJ's recommendations on a fair rate of return for the Company. Aqua and the OCA's Exceptions and Replies to Exceptions on the overall rate of return are based on their respective Exceptions and Replies to Exceptions regarding the ALJ's recommended capital structure, proxy group, and the cost of common equity, *supra.*

4. Disposition

For the reasons discussed above, we have adopted the ALJ's recommendation as to the appropriate capital structure and cost of debt for Aqua.

Additionally, based on the use of informed judgment and the addition of an upward adjustment for management effectiveness, we have modified the ALJ's recommendation as to the appropriate cost of common equity for the Company. This will, in turn, modify the ALJ's recommended overall rate of return. The table below summarizes our final determinations regarding Aqua's capital structure, cost of debt, and cost of common equity, as well as the resulting weighted costs. As Table 7 indicates, we shall set an authorized overall rate of return for Aqua at 7.24%.[66] We shall apply this rate of return, as set forth in Table IA to each of the rate tables that are attached to the Commission Tables Calculating Allowed Revenue Increase at the end of this Opinion and Order.

Type of Capital	Ratio	Cost Rate	Weighted Cost
Long-Term Debt	46.05%	4.00%	1.84%
Common Equity	53.95%	10.00%	5.40%
Total	100.00%		7.24%

Table 7: Aqua Capital Structure – Authorized Overall Rate of Return

XI. Rate Structure

A. Cost of Service

1. Positions of the Parties

Cost allocation studies are used to allocate the total water and wastewater cost of service to the various customer classifications based on established principles of cost-causation with the fundamental purpose of aiding in the accurate and reasonable design of rates. *See* R.D. at 82.

[66] We note that there are additional rate issues pertaining to the elements in the proposed base rate increase addressed later in this Opinion and Order and not included here simply because the Order follows the structure of the Recommended Decision for ease of reference by the reader.

In this proceeding, none of the Parties disputed the method used by Aqua to calculate the cost of service for its water operations and its wastewater operations. In each of the studies prepared, the total costs of service are allocated to the various customer classifications in accordance with generally accepted cost of service principles and procedures. Aqua St. 5 at 3, 19.

Aqua's cost allocation study for its water operations is included in Aqua Exh. 5-A, Part I. The method used for the allocation water cost of service was based on the Base-Extra Capacity Method for allocating costs to customer classifications. This method is described in the 2017 and prior editions of the *Water Rates Manual*, published by the American Water Works Association (AWWA). Aqua Exh. 5-A, Part I at 3. The four basic categories of cost responsibility that are considered using this method are base, extra capacity, customer, and fire protection costs. *Id.*

Aqua's cost allocation study for its wastewater operations is included in Aqua Exh. 5-B, Part I. The method used for the allocation of wastewater cost of service incorporates the functional cost allocation methodology described in the text "Financing and Charges for Wastewater Systems," Manual of Practice No. 27, published by the Water Environment Federation. Aqua Exh. 5-B, Part I at 2-3. This method is recognized for allocating the cost of providing wastewater service to customer classifications in proportion to the classifications' use of the commodity, facilities, and services. *Id.* Aqua prepared separate cost allocation studies for its wastewater Base Operations and the separate operating divisions for Limerick, East Bradford, Cheltenham, East Norriton and New Garden. *See* Aqua St. 5 at 18-19. The separate operating cost allocation studies from the Base Operations are wastewater systems acquired since the *Aqua 2018 Rate Case*. Aqua St. 1 at 7.

2. Recommended Decision

The ALJ recommended that the cost of service study methods used by Aqua for its water and wastewater operation be approved because they are reasonable and consistent with past practice. R.D. at 83.

3. Disposition

No Party filed Exceptions on this issue. Finding the ALJ's recommendation to be reasonable, we adopt it without further comment.

B. Cost of Service – Wastewater

1. Positions of the Parties

Both I&E and the OCA recommended that Aqua be required to prepare ongoing cost allocation studies for the wastewater systems acquired by the Company under Section 1329 of the Code, 66 Pa. C.S. § 1329, in future base rate cases. Additionally, I&E and the OCA argued that the Company should be required to file two separate revenue requirements going forward. These recommendations would require Aqua to prepare a cost of service study (COSS) and revenue requirement for (a) combined Wastewater Zones 1 through 6 (consisting of the Company's legacy systems), (b) combined Wastewater Zones 7-11 (representing the systems acquired under Section 1329 of the Code prior to this base rate proceeding),[67] and (c) each additional

[67] Specifically, these Wastewater Zones are as follows: Zone 7-Limerick, Zone 8-East Bradford, Zone 9-Cheltenham, Zone 10-East Norriton, and Zone 11-New Garden. *See* Aqua Volume 5, Exh. 5-B, Part II, Schs. LMK, EB, CH, EN and NG.

system acquired after this proceeding under Section 1329. I&E M.B. at 65-66; OCA M.B. at 84-86.

I&E argued that combining Wastewater Zones 7 through 11 into one COSS in Aqua's next base rate case is important because these zones include systems acquired under Section 1329 and represent a unique group of zones and cost recovery requirements. Therefore, I&E recommended that these zones should continue to be grouped into one COSS in future cases. I&E also reasoned that it is important to distinguish the difference between these systems and systems not acquired under Section 1329 because of the generally higher cost of providing service to customers in these systems acquired under Section 1329. I&E M.B. at 65-66 (citing I&E St. 5 at 66).

The Company opposed the recommendations of I&E and the OCA stating that the decision to require separate cost allocation studies for future wastewater acquisitions should not be pre-determined but should be evaluated in such future proceedings. Aqua further noted that it has never been required to carve out water and wastewater acquisitions in this manner, after the initial rate case post-acquisition. Additionally, the Company asserted that because the acquired systems are similarly operated as the legacy systems, no advantage could be gained on a cost of service basis by separating these systems. Aqua also contended that the Commission should not dictate how the Company will file its next base rate proceeding absent its agreement, citing the general principle that the Commission should refrain from acting as a super board of directors. Moreover, Aqua argued, the recommendations frustrate the goal of single tariff pricing and consolidation of rate zones. Aqua M.B. at 219-20; Aqua R.B. at 93.

2. Recommended Decision

The ALJ recommended that the Commission adopt the positions advanced by I&E and the OCA that Aqua be required to prepare separate COSS and revenue requirements in its next base rate proceeding. R.D. at 82-83.

The ALJ reasoned that this base rate filing emphasizes the importance of tracking the implications of the acquisition of water and wastewater systems and the effect of those acquisitions on rates and cost of service. In acknowledging that consolidating rate zones is important, the ALJ emphasized the importance of appropriately tracking the cost to serve the acquired systems – and the steps taken to move rates in these systems closer to the cost of service – while ensuring that other ratepayers are not subsidizing service to these customers indefinitely. The ALJ considered the proposals to be reasonable and sensible and well within the Commission's mandate to ensure that a utility's rates are just and reasonable and meet the public interest. *Id*. at 83.

3. Exceptions and Replies

In its Exception No. 8, Aqua argues that the ALJ erred by ordering the Company to prepare a separate COSS for each system acquired under Section 1329 of the Code that is included in the next base rate proceeding following such acquisition. Aqua Exc. at 29-31.

Initially, Aqua contends that the Recommended Decision ignores applicable appellate precedent, citing *City of Pittsburgh v. Pa. PUC*, 526 A.2d 1243 (Pa. Cmwlth. 1987), *appeal denied*, 517 Pa. 628, 538 A.2d 880 (1988) (*City of Pittsburgh*). The Company asserts that in *City of Pittsburgh* the Commonwealth Court specifically affirmed a prior Commission order that declined to condition a water utility's proposed consolidation of rate districts upon the maintenance of separate records for each district. Aqua argues that, consistent with this case, it should not be required to maintain and prepare separate studies and revenue requirements in its next base rate proceeding. Aqua Exc. at 30.

The Company further contends that the Recommended Decision disregards the impacts of imposing this requirement on Aqua relative to other water and wastewater utilities in Pennsylvania. According to Aqua, this requirement will result in significant accounting, tracking, operational and rate impacts that would also frustrate the Commission's policy supporting single tariff pricing and consolidation. Likewise, Aqua continues, the increased costs and complications associated with preparing separate cost allocation studies would likely put the Company at a competitive disadvantage from other bidders in future acquisition opportunities. *Id*. (citing Aqua M.B. at 219).

Furthermore, Aqua submits that, for new acquisitions, the recommended requirements should be analyzed in the context of future Section 1329 acquisition proceedings, and not in this base rate case. The Company submits that the Commission should not require Aqua to indefinitely prepare separate costs of service and revenue requirements for future acquired systems, where it is not known whether and when further systems will be acquired. Aqua Exc. at 30-31.

In its reply, I&E argues that the ALJ properly recommended that the Commission adopt its recommendations regarding recently acquired Section 1329 systems and those acquired subsequent to this base rate proceeding. I&E asserts that the ALJ correctly emphasized the importance of tracking the implications of the acquisitions under Section 1329 and the effect of those acquisitions on rates and cost of service. I&E adds that the ALJ noted the importance of consolidating rate zones. However, I&E asserts, the ALJ correctly determined the need to appropriately track the cost to serve Section 1329 acquired systems and the steps to move rates in these systems closer to the cost of service while ensuring that other ratepayers are not subsidizing service indefinitely. I&E R. Exc. at 9-10.

In its reply, the OCA asserts that the ALJ's recommendation is reasonable given the significant impact that Section 1329 acquisitions had on rates for wastewater and water customers in this proceeding. OCA R. Exc. at 12-14.

The OCA argues that Aqua's objections to the recommendations on the basis that it would place an extra burden on Aqua relative to other water and wastewater utilities are misplaced. If other utilities are acquiring systems under Section 1329, the OCA submits, then they will be in the same situation that Aqua was in the current base rate case where it provided one COSS for legacy systems and individual COSSs for the systems acquired prior to the base rate case. According to the OCA, an individual COSS has been adopted by the Commission for every Section 1329 acquisition approved to date and it is reasonable to assume the Commission will continue to apply it uniformly to Aqua's competitors. OCA R. Exc. at 12.

The OCA contends that the main distinction in this proceeding is that Aqua would be preparing only one additional COSS for the combined Section 1329 systems included in this case. Regarding Aqua's concerns of increased costs and complications of preparing one additional COSS for those systems, the OCA asserts that the Company does not quantify such costs. Instead, the OCA cites to the rate case expense claim in the current proceeding – $400,000 on "Engineering, Cost Allocation and Depreciation"– and compares it with the purchase price of the five systems Aqua already acquired under Section 1329, which ranged from $5 million to $75 million, or an average of $34.4 million. OCA R. Exc. at 12-13 (citing Aqua Exh. 1-C, Sch. C-4.4). The OCA argues that even if COSSs and cost allocation represented the entire $400,000 in this case, ignoring that 91.51% of rate case expense is allocated to water operations, the cost would represent only 1% of the average purchase price of the Section 1329 systems in this case. The OCA submits that this cost to Aqua cannot reasonably be considered a meaningful competitive disadvantage. OCA R. Exc. at 13.

The OCA also criticizes Aqua's concerns about imposing future requirements indefinitely in this base rate case because it is not known whether and when further systems will be acquired. Citing to Aqua's three pending Section 1329 applications, the OCA submits that establishing a requirement for a separate COSS for Section 1329 acquisitions in this case would avoid the need for the Parties and the Commission to address it in every Section 1329 proceeding.[68] The OCA proffers that the continuing need for this requirement could be evaluated in the next base rate proceeding. *Id*.

The OCA further objects to Aqua's contention that preparing a separate COSS would frustrate the policy of single tariff pricing. Regarding the citation to *City of Pittsburgh*, which upheld the Commission's decision to not require a water utility to maintain separate records for rate districts after they were consolidated, the OCA contends the Commonwealth Court's decision is distinguishable. Here, the OCA asserts, Aqua has not reached the point of consolidating Section 1329 systems with its legacy systems. Rather, the OCA emphasizes that Aqua has proposed to reduce its legacy rate zones from six to five and for each Section 1329 system to stay in its own, separate rate zone. OCA R. Exc. at 13-14 (citing Aqua St. 5-R at 21; Tariff Sewer No. 3).

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[68] The OCA notes there are three pending Section 1329 proceedings: *Application of Aqua Pa. Wastewater, Inc.*, Docket No. A-2019-3015173 (Delaware County Regional Water Quality Control Authority Wastewater System Assets); *Application of Aqua Pa. Wastewater, Inc.*, Docket No. A-2021-3026132 (East Whiteland Township Wastewater System Assets); and *Application of Aqua Pa. Wastewater, Inc.*, Docket No. A-2021-3027268 (Williston Township Wastewater System Assets). The OCA also references the recent acquisition approval in the *Application of Aqua Pa. Wastewater, Inc.*, Docket No. A-2021-3024267 (Order entered January 13, 2022) (Lower Makefield Township Wastewater System Assets). OCA R. Exc. at 13, n.8.

Additionally, the OCA argues that in this case Aqua proposes a one-third recovery of its wastewater revenue requirement from water customers, which moves all customers further from paying rates that reflect their indicated cost of service. OCA R. Exc. at 14 (citing OCA St. 4 at 4 (Table I); Aqua Exhs. 5-A, Part I, 5-B, Part I). The OCA submits that the ALJ correctly addressed the concerns about subsidies between water and wastewater and between the legacy and acquired wastewater systems in the Recommended Decision and appropriately adopted the proposal of I&E and the OCA. OCA R. Exc. at 14 (citing R.D. at 83).

4. Disposition

We begin by addressing the contention that an individual COSS has been adopted by the Commission for every Section 1329 acquisition approved to date. *See* OCA R. Exc. at 12. In the recent Section 1329 application by Pennsylvania-American Water Company (PAWC) to acquire the water and wastewater system assets of Valley Township, the parties to that proceeding filed a Joint Petition for Approval of Unanimous Settlement of All Issues (PAWC Settlement) which the Commission approved without modification. *Application of Pennsylvania-American Water Company*, Docket Nos. A-2020-3019859 and A-2020-3020178 (Order entered October 28, 2021) (*PAWC – Valley Township Order*). The PAWC Settlement did not require separate COSSs related to the Valley Township acquisitions in PAWC's next base rate case nor did the Commission modify the Settlement to impose such a requirement. *Id*.

Our decision in the *PAWC – Valley Township Order* is illustrative of the importance of analyzing the necessity of COSSs within the context of individual Section 1329 acquisition proceedings. Although there is a benefit to having COSS data pertaining to Section 1329 acquisitions available in a base rate proceeding subsequent to an application approval, it is apparent from the PAWC Settlement – which included the statutory advocates as signatories – that it need not be mandated within all Section 1329 proceedings. We decline here to pre-judge the issue in all future Section 1329 proceedings when the facts and circumstances of that individual proceeding may not necessarily require a cost of service analysis. Moreover, we shall not impose such a blanket mandate requiring COSSs on all future Section 1329 proceedings involving Aqua when the Commission did not impose such a requirement in an individual application proceeding involving another regulated service provider. However, our decision herein shall not be deemed to limit the authority of the Commission to require the preparation of cost allocation studies for systems acquired in individual Section 1329 proceedings as the circumstances may warrant.

Regarding the proposal to maintain ongoing, separate COSSs for those systems acquired under Section 1329 of the Code prior to this base rate proceeding, we note that the Commission first directed the filing of a cost of service analysis as a condition of approval in Aqua's Section 1329 acquisition of the wastewater system assets of New Garden Township and the New Garden Township Sewer Authority. *Application of Aqua Pennsylvania Wastewater, Inc.*, Docket No. A-2016-2580061 (Order entered June 29, 2017) (*New Garden*).

The intention of the conditions in the *New Garden* proceeding and similar directives in other Section 1329 proceedings was, in part, to inform the Parties and the Commission of the overall rate impact that the acquisition will have on customers within the context of the *next* base rate proceeding. *See New Garden* at 69-70. It was not to impose ongoing conditions indefinitely in all subsequent rate cases.

Thus, we shall grant Aqua Exception No. 8 and modify the Recommended Decision accordingly.

C. Revenue Allocation

1. Positions of the Parties

Aqua noted that under *Lloyd v. Pa. PUC*, 904 A.2d 1010, 1020 (Pa. Cmwlth. 2006) (*Lloyd*), cost of service is the "polestar" of utility rates, and a proposed revenue allocation will only be found to be reasonable where it moves distribution rates for each class closer to the full cost of providing service. Aqua provided that its proposed revenue allocation for both water and wastewater involves a determination of: (1) the allocated cost responsibilities and the percentage of revenue under existing rates; and (2) the percentage of cost responsibilities and percentage of *pro forma* revenues under proposed rates for each customer classification. Aqua M.B. at 211-12 (citing *Lloyd* at 1020). Aqua submitted that, upon making such determinations, the Company: (1) proposed allocating revenues to each customer class that would be required to move that class toward the cost of service; and (2) determined an amount of wastewater revenues to be recovered in water rates, pursuant to Section 1311(c) of the Code (commonly referred to as Act 11).[69] Aqua M.B. at 212 (citing Aqua St. 5 at 10, 21;

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[69] Section 1311(c) of the Code:

> When any public utility furnishes more than one of the different types of utility service, the commission shall segregate the property used and useful in furnishing each type of such service, and shall not consider the property of such public utility as a unit in determining the value of the rate base of such public utility for the purpose of fixing base rates. A utility that provides water and wastewater service shall be exempt from this subsection upon petition of a utility to combine water and wastewater revenue requirements. The commission, when setting base rates, after notice and an opportunity to be heard, may allocate a portion of the wastewater revenue requirement to the combined water and wastewater customer base if in the public interest.

Aqua Exh. 5-A, Part I, Sch. A; Aqua Exh. 5-B, Part I, Sch. WW-A; 66 Pa. C.S. § 1311(c)).

Aqua explained that Act 11 allows a utility that provides both water and wastewater services to allocate a portion of the wastewater revenue requirement to the combined water and wastewater customer base if doing so is in the public interest. Aqua M.B. at 213 (citing *Aqua 2018 Rate Case*, additional citations omitted). Aqua further explained that the public interest is served if properly incurred costs to upgrade a nonviable system can be allocated to the combined wastewater and water customer base. Aqua provided that the Commission noted that one of the benefits of Act 11 is that the costs of necessary upgrades which can be substantial can be spread among the common customer base of water and wastewater utilities. Aqua M.B. at 214-215 (citing Docket No. M-2012-2293611 (Tentative Implementation Order entered May 12, 2012, and Final Implementation Order entered August 2, 2012).

In order to provide a direction for gradualism and avoid substantial rate shock to wastewater customers who will be subject to their first rate increases resulting from a Commission rate case, the Company allocated a portion of the wastewater revenue requirement to its water customers. Aqua M.B. at 215-216 (citing Aqua St. 1-R at 23-25). Aqua determined its Act 11 allocation from wastewater to water rates "by subtracting the proposed level of wastewater revenue after various increases from the *pro forma* cost of wastewater service for the twelve months ended March 31, 2023 from the revenue requirement for each area." Aqua M.B. at 216 (citing Aqua St. 5 at 10; 66 Pa. C.S. § 1311). After increasing and consolidating various wastewater rates to a level that moved each division towards the cost of service while mitigating significant rate impacts, the Company proposed to allocate $20,818,925 of the remaining shortfall

66 Pa. C.S.§ 1311(c).

from wastewater revenues to water customers.[70] Aqua St. 1-R at 2-3; Aqua Exh. 1-A(a). Aqua noted that this allocation represents approximately 30% of the Company's proposed revenue requirement from wastewater to water. Aqua M.B. at 216 (citing Aqua St. 1-R at 24).

Aqua proposed that if the Commission approves a rate increase that is less than that proposed by the Company, that the scale back (or reduction) be applied proportionately based on the Company's proposed revenue allocation. Aqua further proposed that no wastewater scale back occur until the total wastewater Act 11 allocation is eliminated, and any scale back after the Act 11 allocation is eliminated be based on the Company's proposed rates. Aqua M.B. at 265 (citing Aqua St. 5-R at 19-20, 24-25).

I&E's witness, Mr. Joseph Kubas, disagreed with the Company's proposal that its water customers subsidize wastewater customers by approximately $20.8 million because it is large and unreasonable. Mr. Kubas contended that water customers are not wastewater customers, and each utility service should recover as much of the cost to provide that service as possible. I&E M.B. at 70; I&E St. 5 at 7-8. Further, Mr. Kubas contended that the Company did not demonstrate how allocating 30% of the cost of operating wastewater systems to water customers is reasonable. I&E St. 5-SR at 6.

I&E submitted that Mr. Kubas created a rate design that applies an Act 11 subsidy from wastewater to water consistent with cost of service principles and is in the public interest. Accordingly, I&E recommended that the Company's proposed water subsidy be reduced by $5,072,876. I&E St. 5-SR at 4-5; I&E Exh. No. 5, Sch. 1 at 1. Subsequently, in surrebuttal testimony, Mr. Kubas revised his recommended reduction to

[70] Initially, Aqua submitted that wastewater revenues of $20,839,425 be allocated to water customers. Aqua M.B. at 216.

the subsidy necessary for wastewater systems operation by $5,044,324. I&E St. 5-SR at 8; I&E Exh. 5-SR, Sch 1 at 1.

With regard to any scale back that may result if the Commission approves a rate increase that is less than that proposed by the Company, I&E submitted that the Company's proposed rates should be scaled back to produce the revenue requirement allowed by the Commission. I&E further proposed that, to determine the amount of the Act 11 subsidy revenue requirement to be allocated to water operations, the wastewater operations revenue requirements should be determined first, and that the water rates should then be scaled back to recover the resulting water operations' full revenue requirement. Regarding wastewater, I&E recommended that no scale back of wastewater rates should occur until the total Act 11 wastewater subsidy is eliminated. I&E R.B. at 55-56 (citing I&E M.B. at 71).

Similar to I&E, the OCA disagreed with the Company's proposal for its water customers to pay approximately $20.8 million to subsidize its wastewater operations because the wastewater rates would not support a reasonable relationship to the utility's cost of serving the wastewater customers. According to the OCA, it is not in the public interest to use Section 1311(c) and Section 1329 in combination to require that water customers subsidize approximately 75% of the revenue requirement generated by the FMV premiums for the five wastewater systems acquired under Section 1329.[71] OCA R.B. at 46-47 (citing OCA M.B. at 89-91; OCA St. 4 at 7-8).

The OCA submitted that its proposed Act 11 wastewater to water subsidy of $11.774 million is more moderate and in the public interest than that proposed by the other Parties because it recognizes that the Company's water customers do not receive a

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[71] Acquired systems or customers represent Rate Zones 7 through 11, or systems/customers that were acquired by the Company since its last rate proceeding.

direct or indirect benefit from FMV premiums paid to residents of the seller municipalities and the impact of rate increases will be mitigated on the Company's legacy wastewater customers by shifting a substantial amount of their share of the wastewater increase to water customers.[72] OCA R.B. at 47. The OCA asserted that its proposed Act 11 subsidy recognizes the benefit that customers of the acquired Section 1329 systems receive from the FMV premiums and mitigates the impact of the rate increases by shifting their share of the wastewater increase to water customers. OCA R.B. at 47 (citing OCA St. 4 at 3-4, 7-9; I&E St. 5 at 66). The OCA also proposed that, if the Commission adopts the OCA's recommendation that assigns more revenue requirement to the five wastewater systems acquired under Section 1329, then the revenue requirement calculation should be based on the Company's authorized ROE. In this manner, the OCA explained that if the Commission adopts a different capital structure and/or lower ROE than proposed by the Company, then the scale back should first reduce the revenue requirement associated with the FMV premiums, to the benefit of the acquired customers. The OCA further recommended that if the Commission reduces the revenue requirement for non-ROR reasons, then the benefit should be applied to reduce the subsidy by water operations. OCA R.B. at 53-54 (citing OCA M.B. at 96-98; OCA St. 4 at 11-12).

The OSBA criticized the Company's proposed revenue allocation for water service as being unjust, unreasonable, and in violation of *Lloyd* because it fails to move the Residential, Public, Other Water Utilities and Private Fire Protection customer classes closer to their respective cost of service. OSBA R.B. at 7-8 (citing OSBA M.B. at 9-10; *Pa. PUC v. City of Bethlehem-Water Department*, Docket No. R-2020-3020256 (Order entered April 15, 2021) (*City of Bethlehem*) at 36; *Lloyd*). The OSBA also asserted that the Company's proposal to move each customer classification toward its appropriate

[72] Legacy systems or customers represent Rate Zones 1 through 6, or systems/customers that were under the Company at the time of its last rate case proceeding.

percentage cost of service without isolating the Act 11 allocation has no legal foundation. OSBA R.B. at 9-11 (citing OSBA St. 1-S at 4-8).

The OSBA's witness, Mr. Brian Kalcic, proposed an alternative revenue allocation for water service, exclusive of Act 11 considerations, to move customer classes toward their respective costs of service. OSBA R.B. at 8-9 (citing OSBA Exh. BK-1 W, Schs. BK-4W, BK-5W). The OSBA averred that isolating Aqua's claimed water cost of service from Act 11 subsidies is necessary because Act 11 addresses the recovery of proposed wastewater subsidies and is not related to the water cost of service. The OSBA explained that its proposed revenue allocation approach assigns a greater revenue responsibility to the Residential class than under the Company's proposal because the Company's proposed revenue allocation actually moves the Residential class away from its cost of service. The OSBA notes that in this proceeding, any revenue allocation that moves all classes toward cost of service must assign greater revenue responsibility to the Residential class. OSBA R.B. at 11-12. Regarding wastewater service, the OSBA submitted that the Company's proposed Act 11 revenue requirement be reduced by assigning an additional total increase to Aqua's Base and New Garden wastewater divisions. OSBA R.B. at 15 (citing OSBA St. 1-S at 1-3; OSBA St. 1 at 15-16).

Regarding the Company's proposed scale back of its proposed revenue allocation, the OSBA asserted that: (1) because the Company's proposed revenue allocation is cost based, using it as a starting point for any scale back is not valid; and (2) a separate scale back for reductions in the Company's allowed water service revenue requirement is necessary. OSBA R.B. at 16-17 (citing OSBA St. 1-R at 8-11). The OSBA proposed that if the Commission awards the Company a water service revenue increase that is less than Aqua's requested amount and exclusive of Act 11 considerations, then the OSBA's recommended class increases for water service should be proportionately scaled back. OSBA R.B. at 17 (citing OSBA M.B. at 19; OSBA Exh. BK-1 W, Sch. BK-4W). The OSBA also proposed that, at the conclusion of this proceeding, the Act 11 revenues assigned to water classes should be subject to a separate scale back of Aqua's proposed allocation of Act 11 revenues to water customers. OSBA R.B. at 18 (citing OSBA M.B. at 20).

Aqua LUG submitted that the Company's proposed revenue allocation fails to sufficiently move the customer classes towards cost of service. Therefore, Aqua LUG's witness, Mr. Richard A. Baudino, proposed adjustments to the Company's proposed revenue allocation that would result in most customer classes moving closer to their costs of service, consistent with *Lloyd*. Specifically, Mr. Baudino recommended as follows: (1) move the Residential class Relative Rate of Return (RROR) from 0.96 to 0.98; (2) move the Commercial class RROR from 1.04 to 1.02; (3) move the Industrial class RROR from 0.93 to 0.99; and (4) move the Public class RROR from 1.18 to 1.15. Mr. Baudino also recommended that, in the spirit of gradualism, any excess revenue requirement above the Industrial customer cost of service should be allocated to the Residential customer class. Aqua LUG M.B. at 7, 9-10 (citing Aqua LUG St. 1 at 5-6; Aqua LUG Exh.__(RAB-2)).

Aqua LUG provided that Mr. Baudino supported the adjusted revenue allocation recommended by the OSBA witness, Mr. Kalcic, to achieve additional movement towards cost of service. Aqua LUG M.B. at 10 (citing Aqua LUG St. 1S at 3; OSBA St. 1-R at 11-12). Accordingly, Aqua LUG recommended that the Commission should modify the Company's proposed revenue allocation to reflect the OSBA's proposed adjustments or, alternatively, Aqua LUG's proposed adjustments. Aqua LUG M.B. at 7, 11 (citing OSBA St. 1, Exh. BK-1 W, Sch. BK-4W; Aqua LUG St. 1, Exh.__(RAB-2)). Aqua LUG also recommended that, if the Commission approves a revenue increase lower than the proposed revenue allocation, then the approved revenue allocation should be scaled back proportionately. Aqua LUG M.B. at 11-12 (citing Aqua LUG St. 1 at 6).

Masthope submitted that any revenue allocation pursuant to Act 11 and any rate design or rate structure will result in significant increases in wastewater rates for Masthope ratepayers. Masthope R.B. at 6 (citing Masthope M.B. at 19-24; 66 Pa. C.S. § 1311). Further, Masthope asserted that the Act 11 subsidy adjustments proposed by I&E and the OCA will result in unjust and unreasonable rates that would have an adverse effect on Masthope's wastewater customers. Moreover, Masthope recommended that, if the Commission approves revenues in amounts less than what the Company proposed, any increased revenue requirement for water and wastewater customers and the amount of revenue support to be provided by water customers should be distributed in a manner consistent with the Company's proposal. Masthope M.B. at 20-22 (citing Masthope St. 2-R at 3-5). Additionally, Masthope proposed that, in anticipation that increases in costs and the potential need for cross-subsidies will continue for several years, the Commission should hold Aqua's wastewater revenue increase at the Company's proposed level while reducing the water increase to achieve a reduction in any computed cross subsidies. Masthope M.B. at 22.

2. Recommended Decision

In her Recommended Decision, the ALJ determined that Aqua's allocation of revenues between all water and wastewater customer classifications is reasonable and should be approved. Regarding the Act 11 subsidy allocated to water customers, the ALJ recommended that the Commission adopt I&E's proposed methodology for allocating revenue and designing wastewater rates. R.D. at 91, 93.

The ALJ recommended an additional adjustment for shifting the wastewater revenue requirement to water customers. Specifically, the ALJ provided that the wastewater revenue is based upon the expenses associated with wastewater service, such as bad debt expense, which is determined using an uncollectible accounts factor. The ALJ concluded that because the Company would incur bad debt expenses from water customers at the water uncollectible accounts factor rather than at the wastewater uncollectible accounts factor, it is not reasonable to charge water customers for bad debt expenses at the wastewater uncollectible accounts factor because water customers will ultimately pay the revenue requirement that was shifted to them. Therefore, the ALJ reasoned that, when wastewater revenue requirement is shifted to water customers, the gross wastewater revenue requirement must be reduced to a net basis using the revenue factor for each service, as reflected in Table I(B) for each of the wastewater tables in the Appendix of the Recommended Decision, to determine the water net income that the Company will receive and the wastewater net income that the Company would have received. The ALJ found that the difference between these net values is grossed up using the water revenue factor before being deducted from the gross allocated wastewater revenue requirement, thereby resulting in an adjusted gross water revenue requirement that provides the Company the same net income from water customers that it would have received from wastewater customers. R.D. at 86-87. Table Act 11 in the Appendix of the Recommended Decision provides the detail of the ALJ's adjusted gross water revenue requirement.

The ALJ addressed Mr. Kubas' recommendation to shift some of the revenue increase from the acquired systems (Rate Zones 7 through 11) to the legacy systems (Rate Zones 1 through 6).[73] R.D. at 87-88. Specifically, the ALJ discussed Mr. Kubas' view that, although each type of utility service should recover the cost of providing service as much as possible to the subsidy allocated to water customers, eliminating the subsidy would result in large increases to the monthly charges and rates for residential and commercial wastewater customers. The ALJ continued that

[73] We note that in her Recommended Decision, the ALJ presented a table prepared by Mr. Kubas "which summarized each party's proposed allocation of revenue." R.D. at 87-88 (citing I&E Exh. 5, Sch. 1). As discussed, *infra*, we shall strike the table presented at the top of page 88 in the Recommended Decision, consistent with this Opinion and Order.

Mr. Kubas reduced the subsidy allocated to water customers by recommending that the usage rate increases to the average residential customers be limited. The ALJ also addressed the proposed alternative Act 11 subsidy analyses offered by the OCA and the OSBA. R.D. at 88-89 (citing I&E St. 5 at 7-8, 10, 35-36, 38; OCA St. 4 at 1; OSBA St. 1 at 16-17).

The ALJ explained that in public utility regulation, and particularly in infrastructure improvements, it is not uncommon to approve the socialization of costs which benefit a subset of consumers over a larger group of consumers. The ALJ noted Act 11 permits the costs associated with wastewater system improvements to be shifted to water customers to avoid steep rate hikes to wastewater customers. The ALJ addressed Aqua's statement that the proposed revenue increase for both water and wastewater is primarily driven by investment in infrastructure, noting that it is important to understand that for the Acquired Systems, both the buyer, Aqua, and the selling municipalities should know that at the time of acquisition customers were likely paying rates that were well below the cost of service, either because rates had not been increased or facility improvements had been deferred. R.D. at 90.

Therefore, the ALJ reasoned that to meet the increased costs associated with system improvements, rates will need to be increased, and the increases might be substantial. The ALJ also addressed the responsibility of the community representatives of the acquired systems who sold their systems to avoid increasing taxes or utility rates or both. Specifically, the ALJ reasoned that such communities achieved a benefit from the revenue generated by the sale of their wastewater systems, and, because these communities have already enjoyed some benefit from the sale of the system, it is not equitable to the Company's water customers to mitigate the resulting increases in expenses to care for the acquired systems. R.D. at 90. Moreover, the ALJ reasoned that it is not fair for water customers to take on the burden of filling the gap between the cost of service to serve these wastewater systems because the proceeds Aqua paid municipalities to acquire the wastewater systems are used by those municipal governments to reduce, stabilize, or eliminate municipal costs recovered through taxes to the benefit of the wastewater customers residing within those municipalities. *Id.* (citing Aqua St. 1-R at 25). The ALJ highlighted that the Commission relied on these benefits when it determined that the acquisitions were in the public interest. R.D. at 90.

According to the ALJ, although increasing rates gradually to avoid rate shock is important to consider in setting reasonable rates, such gradualism is only one consideration among many, and some level of rate shock is inevitable. The ALJ reasoned that Aqua's approach of allocating 30% of the proposed wastewater revenue requirement to water customers is arbitrary and will not result in just and reasonable rates. Therefore, the ALJ found that, given the consideration of rate shock in the setting of rates in certain circumstances, Aqua's proposal to shift 30% of the wastewater revenue requirement to water customers is not equitable. *Id.*

Additionally, the ALJ addressed the agreement of both I&E and Aqua that no scale back of the Company's proposed wastewater rates should occur until the total wastewater allocation is eliminated. The ALJ found that any scale back of water rates will first reduce the Act 11 allocation. R.D. at 90-91 (citing Aqua St. 5-R at 25; *Lloyd*).

Ultimately, the ALJ recommended adoption of I&E's proposed methodology for allocating revenue and designing wastewater rates, reasoning that I&E's approach considers the number of water and wastewater customers in each system and balances the goal of moving rates toward alignment with the cost of service while mitigating some of the large rate increases that would result if no allocation of wastewater revenue was approved. The ALJ found that I&E's approach addresses the benefits received by the communities serviced by the acquired systems from the sale of their systems to the Company, adding that I&E's method is less complicated than the method advocated by the OCA. R.D. at 91.

Regarding water allocation, the ALJ reasoned that Aqua and the OCA's approach to revenue increases for water is more reasonable than the proposed modifications of the OSBA and Aqua LUG. *Id.* at 91. The ALJ found that, but for the Act 11 subsidy allocated to water customers, Aqua's allocation of revenues between all water customer classifications and all wastewater customer classifications is reasonable and should otherwise be approved. R.D. at 91, 93 (citing OSBA M.B. at 9-20; Aqua LUG M.B. at 8-11).

The ALJ highlighted the OCA's argument that the results of the OSBA's witness, Mr. Kalcic's, class revenue allocations (before the Act 11 subsidy) are not reasonable. R.D. at 91 (citing OCA St. 4R at 5-7). Specifically, the ALJ observed that, although the Residential and Industrial classes are currently earning close to parity, Mr. Kalcic's proposal would increase their percentage of system average revenue responsibility. *Id.* Similarly, the ALJ observed that concurrently, the Commercial class is also earning close to parity, but Mr. Kalcic recommended that this class receive 74% of the system average percentage increase. R.D. at 92. The ALJ also reasoned that Aqua's proposed allocation of revenues views cost of service as a whole and does not attempt to exclude the Act 11 allocation from its analysis. *Id.* Further, the ALJ reasoned that Aqua moves each customer classification toward its appropriate percentage cost of service, including Act 11 allocation. R.D. at 92.

In reviewing the Company's proposed revenue allocation compared to the OSBA's recommended revenue allocation, the ALJ noted that it appears that the OSBA's recommendations to isolate and remove the Act 11 allocation from its analysis is motivated by its preference to decrease the revenue allocated to non-residential customer classes while increasing the revenue allocated to residential classes. R.D. at 92 (citing Aqua St. 5-R at 5). However, the ALJ emphasized that, from the perspective of customers, the effect of the increase includes both the water increase and the wastewater allocation. Therefore, the ALJ found that Aqua's methodology better reflects the cost of service. R.D. at 92.

The ALJ also addressed Aqua LUG's witness, Mr. Baudino's, proposed reductions to the projected increases to the Commercial and Public classes. R.D. at 93 (citing Aqua LUG St. 1 at 5; Aqua LUG Exh.__(RAB-2)). Specifically, the ALJ agreed with Aqua witness, Ms. Constance E. Heppenstall, that Mr. Baudino's recommendation, which is based on moving a portion of the Industrial class increase to the Residential class due to a larger increase to blocks 5 and 6 of the consumption rates for the Industrial class, would result in RROR between 0.98 and 0.96 and, therefore, should be rejected. R.D. at 93 (citing Aqua St. 5-R at 25). Similarly, the ALJ agreed with the OCA that Aqua LUG does not consider other inherent complexities in this case, including: (1) gradual movement of various divisions to a state-wide rate; (2) the Public Fire revenue subsidy required by statute; and (3) subsidization of wastewater operations by water operations. R.D. at 93 (citing Aqua St. 4R at 12).

3. Exceptions and Replies

a. Aqua Exception No. 9 and Replies

In its Exception No. 9, Aqua submits that the ALJ's recommendation that the Commission accept I&E's methodology for allocating wastewater revenues and wastewater rates under Act 11 should be rejected, and the Company's proposed Act 11 revenue allocation should be adopted. Aqua Exc. at 31, 34 (citing R.D. at 91, 96). Aqua challenges the ALJ's reasoning that the Company's proposed allocation of wastewater revenues is not fair to water customers because the Company and the selling municipalities should know that rates would increase at the time of a wastewater system acquisition as wastewater customers were likely paying rates that were below the cost of service. Aqua Exc. at 31-32 (citing R.D. at 89-90). Aqua counters that the Company demonstrated that justifications advanced by I&E and restated by the ALJ are unreasonable and unsupported by record evidence. Aqua Exc. at 32. Specifically, the Company contends that I&E's testimony: (1) implies that municipal governments believed that the cost of acquiring the subject systems would be carried by existing Aqua customers; and (2) ignores the Company's explanation that, as part of the Section 1329 process, future customer rates will be impacted by the purchase price. Moreover, Aqua notes that, contrary to I&E's arguments, the Company demonstrated that it educates and engages with municipal leaders on the ratemaking process. Aqua Exc. at 32 (citing Aqua M.B. at 218-19).

Aqua also challenges the ALJ's reasoning that: (1) community representatives who decided to sell a system due to increasing taxes and/or utility rates are unable to avoid the consequences of that decision; and (2) the revenue generated by the sale of a community's wastewater system is a benefit to the communities of the acquired systems. Aqua Exc. at 32 (citing R.D. at 90). Specifically, Aqua posits that the ALJ took the testimony of Aqua's witness, Mr. Packer, out of context because Mr. Packer was responding to the proposed Act 11 revenue allocation advanced by the OCA, and although Mr. Packer did not disagree with the benefits to the communities whose systems were acquired by Aqua, he states that, "the principles of gradualism should prevail and be utilized to mitigate these first in rate increases." Aqua Exc. at 32 (citing Aqua M.B. at 217-18; Aqua St. 1-R at 25). Further, Aqua claims that the ALJ ignored Mr. Packer's testimony that over the long-term, the Commission will have sufficient opportunities in subsequent rate cases to adjust the rate design for each of the acquired systems. Aqua Exc. at 32-33 (citing Aqua St. 1-R at 25-26). Aqua asserts that the ALJ, instead, reasoned that each system should be subjected to a large and immediate rate increase in this proceeding because an immediate benefit was obtained by the communities which sold wastewater systems to the Company. Accordingly, Aqua contends that such reasoning highlights that I&E's proposal will result in rate shock. Aqua Exc. at 33.

Aqua also challenges the ALJ's determination that the Company's approach of allocating 30% of the proposed wastewater revenue requirement to water customers is "arbitrary." Aqua Exc. at 33 (citing R.D. at 90). Aqua counters that, although the ALJ cited to *Lloyd*, which rejected the definition of gradualism as limiting a rate increase to 10% of the total bill as "the magic number that will prevent rate shock," the Company explained why its proposal is just and reasonable and does not aver that its proposed 30% allocation is the "magic number." Aqua Exc. at 33 (citing Aqua R.B. at 95-99; Aqua M.B. at 216-225). Further, Aqua notes that given the size and number of the systems acquired since the Company's last base rate case and to mitigate the impacts of the initial rate increase for these systems while still moving each towards the cost of service, it is appropriate for the initial allocation of revenues to be higher. Aqua Exc. at 33 (citing Aqua M.B. at 216; Aqua St. 1-R at 24). Moreover, Aqua notes that the other Parties' alternatives are disruptive to the Company's balanced approach and would subject the customers of the acquired systems to significant and immediate rate increases. Aqua Exc. at 33.

Finally, Aqua argues that I&E's proposed rate zone-specific rate design, and Act 11 revenue allocation proposal, are inappropriate. Aqua posits that the ALJ did not analyze the Company's detailed wastewater rate design proposal beyond determining that I&E's proposed rate design should be adopted as a part of the Act 11 revenue allocation. Aqua Exc. at 34 (citing R.D. at 91; Aqua M.B. at 237-38).

In its Replies, I&E argues that the ALJ considered all of the wastewater revenue allocations presented by the Parties and properly recommended the methodology presented by I&E for allocating revenue and designing the wastewater rates. Further, I&E notes the ALJ's finding that I&E's approach: (1) takes into consideration the number of water and wastewater customers in each system; (2) balances the goal of moving rates toward alignment with the cost of service; and (3) mitigates some of the resulting large rate increases if a wastewater revenue allocation is not approved.

Moreover, I&E avers the ALJ acknowledged that I&E's approach is: (1) more beneficial to the communities served by the systems acquired by the Company pursuant to Section 1329; and (2) less complicated and more logical than the methods advocated by the other Parties. I&E R. Exc. at 10 (citing R.D. at 91).

In its Replies, the OSBA disagrees with the Company's Exception to reverse the ALJ's recommendation that reduces the Company's proposed amount by approximately $10 million. The OSBA avers that it does not oppose the magnitude of the Act 11 subsidy reduction recommended by the ALJ because it argued in this proceeding that the Company's request to recover $20.839 million of the wastewater revenue requirement from water service customers was not supported by the record evidence. The OSBA further notes that, as a result of its proposal to assign additional increases to Aqua's Base and New Garden Divisions, the OSBA's overall proposed wastewater increase and its recommended Act 11 revenue requirement was less than the Company's proposal. Therefore, the OSBA concludes that it supports the ALJ's recommendation to reduce the Act 11 subsidy paid by the Company's water customers. OSBA R. Exc. at 2-3 (citing OSBA St. 1 at 15-17).

In its Replies, the OCA, likewise, submits that the ALJ properly rejected the Company's Act 11 subsidy and rate design, arguing that the subsidy is unreasonable and inconsistent with generally accepted ratemaking principles. The OCA notes that, with regard to the Act 11 subsidy amount, the recommendations of I&E and the OCA are based on the same reasoning that it is not reasonable or in the public interest for water customers, who receive no benefit from wastewater operations or Section 1329 acquisitions, to support a disproportionate share of the revenue requirement driven by those acquisitions. OCA R. Exc. at 16 (citing R.D. at 89-91; 96; OCA St. 4 at 4-5; I&E St. 5 at 66). Further, the OCA contends that establishing a subsidy close to one-third of the wastewater revenue requirement would mean that wastewater rates do not support a reasonable relationship to the utility's cost of serving the customer. OCA R. Exc. at 16 (citing OCA M.B. at 89-91).

The OCA also disagrees with the Company's claims that the subsidy is necessary to mitigate significant rate impacts for the acquired wastewater customers and that the more moderate subsidy recommended by I&E produces wastewater rate increases that are not sufficiently gradual. OCA R. Exc. at 16 (citing Aqua Exc. at 31-33). The OCA posits that the Company neglects the role that FMV ratemaking rate base and the Company's high proposed return on common equity play in worsening the rate impact on the customers of the acquired systems. Therefore, the OCA asserts that it is reasonable to assign more of the revenue requirement generated by the acquired systems. Moreover, the OCA notes that under the ALJ's recommended reduction to the Act 11 subsidy, the acquired wastewater customers and legacy wastewater customers will not pay the full cost of service, and there would still be a $10 million subsidy by water customers. OCA R. Exc. at 16-17 (citing OCA St. 4-SR at 2-3).

b. I&E Exception No. 2 and Replies

In its Exception No. 2, I&E submits that the ALJ erred in using I&E's wastewater increase by class recommendation table that was prepared to support the rebuttal testimony of I&E's witness, Mr. Kubas, instead of I&E's updated wastewater increase by class recommendation table that Mr. Kubas submitted in support of his surrebuttal testimony. I&E explains that Mr. Kubas prepared a table in support of his rebuttal testimony that summarized the proposed revenue allocations set forth in the Parties' direct testimony. However, I&E restates that in the surrebuttal phase of the case, Mr. Kubas revised I&E's proposed wastewater revenue increase by system to reflect revisions to Aqua's original claim, late payment revenues, and proposed revenues, as well as to address the positions of the other Parties. Accordingly, I&E argues that the Commission should rely on the wastewater increases by class which were updated in

Mr. Kubas' surrebuttal testimony. I&E Exc. at 4-5 (citing R.D at 88; I&E St. 5-SR at 4; I&E Exh. 5-SR, Sch. 1 at 1; I&E St. 5-R at 1-23; I&E Exh. 5-R, Sch 1).

In its Replies, Aqua submits that I&E's surrebuttal wastewater revenue allocation should be rejected for the same reasons it argued against adopting I&E's rebuttal proposal. Aqua R. Exc. at 9 (citing I&E Exc. at 4-5).

c. OCA Exception No. 11 and Replies

In its Exception No. 11, the OCA submits that, although it supports the reduction to the subsidy, the OCA's method for allocating the revenue requirement between water and wastewater customers is more reasonable and should be adopted. OCA Exc. at 16 (citing R.D. at 89-91). The OCA asserts that, by allocating a portion of the wastewater revenue requirement to water customers, the OCA's method moves the acquired and legacy system rates closer to their cost of service while mitigating rate increases to all wastewater customers. OCA Exc. at 18 (citing OCA St. 4SR at 1-2; OCA St. 4 at 4-9).

The OCA notes that although I&E's method focuses on the gap generated by each system's revenue requirement, the OCA's method also considers how much of the gap is generated by the FMV premium paid for each acquired system. The OCA argues that, in determining relative burdens, it is not reasonable for the subset of wastewater customers benefiting from the FMV premium to further benefit by having water customers pay the portion of the acquired system's revenue requirement generated by the FMV premium. OCA Exc. at 16-17 (citing OCA R.B. at 46-49; OCA M.B. at 88-89, 91-96; OCA St. 4 at 6-8; OCA St. 4-SR at 2-3).

The OCA also claims that contrary to the ALJ's concerns regarding the complexity of the OCA's recommendation, the additional steps for implementation of the

OCA's method are warranted and not unreasonably complicated. OCA Exc. at 17 (citing R.D. at 91). The OCA explains that the calculated amount of the revenue requirement associated with the FMV premiums is allocated to the five acquired systems such that no system exceeds its cost of service, and the remainder is allocated to the legacy systems. The OCA notes that the Company's proposed class increases for each division are prorated when applied. OCA Exc. at 17 (citing OCA St. 4 at 8-10; OCA Exh. Sch. GAW-4).

Further, the OCA argues that, when compared to the OCA's method, I&E's method recommends that the Cheltenham wastewater system be assigned a larger revenue requirement and, if I&E's method is adopted, then Cheltenham's resulting rates at the Company's revenue requirement would be higher than its cost of service. OCA Exc. at 17 (citing OCA St. 4-SR at 5-6; I&E St. 4-SR at 5, 14). Moreover, the OCA notes that, although it agrees that the wastewater subsidy should be reduced, the revenue allocations should also be guided by cost-causation. Accordingly, the OCA submits that, if the OCA's allocation method is not adopted and if the revenue allocated to the Cheltenham system would otherwise exceed its cost of service, then an adjustment should be made as part of the scale back. OCA Exc. at 17 (citing OCA R.B. at 54).

The OCA also explains that it does not except to the ALJ's recommendation regarding water allocation because, but for the Act 11 subsidy, the ALJ adopted the Company's and the OCA's recommendation. The OCA provides that it is the OCA's understanding that the ALJ accepts the OCA's recommended proportional scale back across the divisions and classes and, other than the Act 11 subsidy, this is consistent with the water revenue increase allocation adopted by the ALJ and supported for the same reasons. OCA Exc. at 18 (citing R.D. at 91-93; OCA R.B. at 55-58; OCA St. 4 at 12-13).

The OCA disagrees with the ALJ's recommendation that adopts I&E's and the Company's scale-back proposal which would not reduce wastewater rates until the Act 11 subsidy is eliminated. OCA Exc. at 18 (citing R.D. at 91; Aqua St. 5-R at 25; I&E St. 5 at 63-64). The OCA recommends a different scale-back approach that would allocate additional wastewater revenue to the acquired systems and legacy systems based on the Company's authorized ROE. Therefore, the OCA maintains that if the Commission adopts a different capital structure and/or a lower ROE than proposed by the Company, then the scale back should first be applied to reduce the revenue requirement associated with the FMV premiums, to the benefit of wastewater customers. Further, the OCA maintains that if the Commission reduces revenue requirement for non-ROR reasons, or the Commission does not adopt the OCA's method for allocating wastewater revenue requirement based on FMV premiums, then the OCA agrees that the benefit should be applied to reduce the subsidy by water operations. OCA Exc. at 18 (citing OCA M.B. at 96-97; OCA St. 4 at 11-12).

In its Replies, Aqua argues that the OCA's proposed allocation of Act 11 revenues was properly rejected because it is neither fair nor reasonable. Aqua counters that the arguments advanced by the OCA in support of its proposed Act 11 revenue allocation are without merit and should be rejected for the same reasons as its revenue allocation proposal. Aqua argues that the OCA's calculation of the revenue requirement associated with FMV premiums: (1) is improper; (2) seeks to mask a large increase to wastewater base customers; and (3) ignores that the Company's proposal already accounts for the premiums which the OCA seeks to undo. Aqua adds that the OCA's scale-back method should be rejected for the same reasons as its proposed revenue allocation. Aqua R. Exc. at 9-10 (citing OCA Exc. 17; Aqua R.B. at 95-98; Aqua M.B. at 220-21, 266).

In its Replies, I&E submits that, upon consideration of all of the proposals set forth by the Parties regarding this issue, it supports the ALJ's recommendation. I&E R. Exc. at 16.

d. OSBA Exception No. 1 and Replies

In its Exception No. 1, the OSBA argues that the ALJ erred in adopting the Company's proposed revenue allocation for its water service customers. OSBA Exc. at 2 (citing R.D. at 93). First, the OSBA disagrees with the ALJ's conclusion that Aqua's methodology better reflects the cost of service compared to those advocated by the other Parties because it is based on "a combined water and wastewater revenue, or 'total bill,' evaluation." OSBA Exc. at 2-3 (citing R.D. at 81, 92). The OSBA argues that the ALJ's conclusion violates the decision in *Lloyd* that ratemaking must be conducted using each specific service's cost of service. OSBA Exc. at 3. The OSBA notes that, when developing a revenue allocation based upon an accepted cost of service study, the ALJ and the Commission must follow the requirements set forth in *Lloyd* because if ratemaking is performed on a combined or total-bill basis, such as Aqua, proposes the true impact of the revenue increases required by the Company's separate water and wastewater cost of service study will be hidden. *Id.* (citing *Lloyd* at 1015, 1020-21).

The OSBA also argues that the Company's proposed water revenue allocation violates the principles of *Lloyd* because it moves each class "toward its appropriate percentage cost of service including the Act 11 allocation." OSBA Exc. at 4 (citing R.D. at 92-93). The OSBA asserts that the plain language of Section 1311(c) of the Code sets the legal standard that must be met in all combined water/wastewater rate cases under Act 11. The OSBA specifically notes that Section 1311(c) provides that "[t]he commission when setting base rates, after notice and an opportunity to be heard, *may allocate a portion of the wastewater revenue requirement* to the combined water and wastewater customer base if in the public interest." OSBA Exc. at 4 (citing 66 Pa. C.S.

§ 1311(c) (emphasis added by the OSBA)). However, the OSBA contends that Section 1311(c) does not provide the legal authority to violate the requirement of *Lloyd* that rates for individual utility services be based on separate cost of service determinations. OSBA Exc. at 4 (citing *Lloyd*). Accordingly, the OSBA contends that the ALJ's approval of Aqua's water revenue allocation on the basis that it moves each class "toward its appropriate percentage costs of service including the Act 11 allocation" must be rejected because the ALJ made her decision without any legal basis set forth in Act 11. OSBA Exc. at 4 (citing R.D. at 92-93).

The OSBA also argues that the Company's revenue allocation violates *City of Bethlehem* where the Commission agreed with the OSBA when it determined that "the proper yardstick for measuring the degree of movement toward cost of service is the change in the absolute level of class subsidies at present and proposed rates." The OSBA asserts that in this case, the ALJ ignored the Commission's standard in *City of Bethlehem* for measuring progress towards cost of service when designing a revenue allocation. OSBA Exc. at 4-5 (citing *City of Bethlehem* at 36). In fact, the OSBA contends that its subsidy analysis demonstrates that the Company's proposed revenue allocation for water service, at the Company's requested revenue requirement level, would result in the Commercial, Industrial, and Public Fire customer classes moving toward cost of service and the Residential, Public, Other Water Utilities and Private Fire customer classes moving away from cost of service. OSBA Exc. at 5-8 (citing OSBA St. 1 at 4, 6-9; OSBA Exh. BK-1 W, Schs. BK-1W, BK-3W). Thus, the OSBA maintains that the Company's proposed revenue allocation for water service, exclusive of Act 11 subsidies, is unjust and unreasonable because it violates *Lloyd* by failing to move all of the customer classes closer to their respective cost-based revenue levels. OSBA Exc. at 8.

Finally, the OSBA further disagrees with the ALJ's finding that Aqua's revenue allocation better reflects cost of service since it moves each customer classification toward its appropriate percentage of cost of service when the Act 11 allocation is included. OSBA Exc. at 8-9. The OSBA argues, however, that the preferred cost metric used by Aqua in support of its revenue allocation is conceptually invalid. In this regard, the OSBA cites the testimony and detailed analysis (see OSBA Exc. at 8-11) of its witness, Mr. Kalcic, in reiterating its position that the Company's proposed class revenue allocation for water service, including Aqua's alternative percentage of cost of service metric, and Aqua's claim that Act 11 revenues should be included in class revenue allocation evaluations, is without legal foundation. OSBA Exc. at 9-11 (citing OSBA St. 1-S at 4-8). Therefore, the OSBA avers that the Company's proposed class revenue allocation for water service must be rejected by the Commission. OSBA Exc. at 11.

In its Replies, Aqua counters that the Company's proposals are consistent with Act 11 and *Lloyd*. Further, Aqua notes that the OSBA essentially is repeating the same arguments it made in its Briefs against the Company's proposed water revenue allocation in favor of its own water revenue allocation. The Company cites to its arguments included in its Briefs against the OSBA's position. Aqua R. Exc. at 10 (citing OSBA Exc. at 11-17; Aqua R.B. at 98-100; Aqua M.B. at 224, 228-29). Additionally, Aqua avers that the OSBA's reliance upon *Lloyd* is misplaced in that the OSBA "treats the allocation of wastewater costs as though they were a separate rate charged to water customers." Aqua R. Exc. at 10.

e. OSBA Exception No. 2 and Replies

In its Exception No. 2, the OSBA submits that the ALJ erred in rejecting the OSBA's proposed water revenue allocation. The OSBA begins its Exception No. 2 by citing to the ALJ's conclusion that "it appears that OSBA's recommendation to isolate and remove the Act 11 allocation from its analysis is motivated by a desire to decrease the revenue allocated to non-residential customer classifications, while increasing the revenue allocated to residential customer classes." OSBA Exc. at 11 (citing R.D. at 92;

Aqua M.B. at 229). In response, the OSBA argues that the ALJ's conclusion with respect to its motivations is baseless. The OSBA submits that its proposed water revenue allocation should be adopted by the Commission because it correctly isolates Act 11 revenues in its proposed revenue allocation. The OSBA explains that its approach of isolating the Company's claimed water cost of service from Act 11 subsidies: (1) is the only revenue allocation sponsored by any Party that follows both the requirements of *Lloyd* and the Commission's decision in *City of Bethlehem*; and (2) is necessary to develop a cost-based water revenue allocation, given that the Company's claimed wastewater cost of service and associated Act 11 subsidies are separate from, and unrelated to, its claimed water revenue requirement. Furthermore, the OSBA maintains that, given that Aqua's proposed revenue allocation moves the Residential class in the wrong direction (*i.e.*, away from the cost of service), the OSBA's revenue allocation assigns greater revenue responsibility to the Residential class because any revenue allocation which corrects the Company's failure to move all classes toward cost of service will assign a greater revenue responsibility to the Residential class. OSBA Exc. at 11-12 (citing OSBA M.B. at 9-14).

The OSBA repeats its argument that the Commission should adopt its alternative water revenue allocation proposal sponsored by its witness, Mr. Kalcic, in this proceeding because it: (1) implements the Company's requested revenue increase; (2) is exclusive of any allocation of Act 11 subsidies; and (3) would move all classes toward their respective cost-based revenue levels without imposing an excessive increase on any class of water customers. OSBA Exc. at 12-15, 17 (citing OSBA St. 1 at 9-11; OSBA Exh. BK-1 W, Schs. BK-4W, BK-5W). Moreover, the OSBA notes that, although it agrees with the Company's method of allocating its Act 11 revenue requirement to its water service classes, the OSBA does not agree with the overall magnitude of the Company's proposed Act 11 revenue requirement. OSBA Exc. at 15-16 (citing OSBA St. 1 at 11, 15, 17; OSBA Exh. BK-1 W, Schs. BK-1W, BK-6W).

In its replies, Aqua counters that the Company's proposals are consistent with Act 11 and *Lloyd*. Further, Aqua notes that the OSBA essentially is repeating the same arguments it made in its Briefs against the Company's proposed water revenue allocation in favor of its own water revenue allocation. The Company cites to its arguments included in its Briefs against the OSBA's position. Aqua R. Exc. at 10 (citing OSBA Exc. at 11-17; Aqua R.B. at 98-100; Aqua M.B. at 224, 228-29).

In its replies, the OCA disagrees with the OSBA's arguments in its Exception No. 2 and opines that the ALJ properly found that the OSBA's recommended total class water increases are unreasonable. The OCA agrees with the ALJ that, from the perspective of the customers, both the water increase and the wastewater allocation are included in the effect of the increases. Further, the OCA states that with the Act 11 subsidy excluded, the results of the OSBA's class revenue allocations are not reasonable. OCA R. Exc. at 18-19 (citing R.D. at 92; OSBA Exc. at 11-17). Moreover, the OCA asserts that, although the Residential, Industrial and Commercial classes are currently earning close to parity, the OSBA's proposal would result in skewed, unreasonable, and inequitable increases because the Residential and Industrial classes would experience a higher percentage of revenue responsibility than that of the Commercial class. OCA R. Exc. at 19 (citing OCA R.B. at 55-58; Aqua M.B. at 228-29; OCA St. 4R at 7, 9-10).

f. OSBA Exception No. 3 and Replies

In its Exception No. 3, the OSBA disagrees with the ALJ's adoption of I&E's recommended wastewater rate design and rate increases because it does not include an analysis of how the Company's Act 11 wastewater subsidies should be allocated to Aqua's customers. OSBA Exc. at 17 (citing R.D. at 91). Thus, the OSBA supports the Company's proposed method of allocating the Act 11 subsidy because, as discussed in more detail below, it is consistent with the OSBA's position that the recovery of Act 11 wastewater subsidies from water customers on a revenue neutral basis by customer class is the only just and reasonable resolution of this issue that is consistent with the requirements of *Lloyd*. OSBA Exc. at 17, 20.

In support of this Exception, the OSBA references its witness, Mr. Kalcic's, review and analysis of the Company's proposed method of allocating its Act 11 revenue requirement to water customers to argue that the Company's proposed wastewater increase would not recover all of the Company's claimed wastewater revenue requirement. OSBA Exc. at 18-19 (citing OSBA St. 1 at 13-14, OSBA Exh. BK-1 WW, Sch. BK-1WW). Further, the OSBA contends that, although Act 11 provides the statutory authority to temporarily recover the costs associated with Aqua's wastewater system from its water customers, Act 11 does not allow for any "cross-subsidization" of customer classes between water and wastewater customers. OSBA Exc. at 19. Moreover, the OSBA argues that Act 11 does not supersede the requirements of *Lloyd*, meaning that the Company's water rates, exclusive of Act 11, must be based primarily on the results of Aqua's water cost of service study. Accordingly, the OSBA requests that the Commission adopt the Company's proposal to recover Act 11 wastewater subsidies from water customers on a revenue neutral basis by customer class because it is just, reasonable, and consistent with the requirements of *Lloyd* and the language of Act 11. OSBA Exc. at 19-20 (citing OSBA St. 1 at 17-18).

In its Replies, the OCA argues that the OSBA's recommended total class water increases are unreasonable and should not be adopted by the Commission. With regard to the OSBA's argument that the ALJ erred in not accepting the OSBA's proposal with regard to the Act 11 allocation subsidy between Residential and non-Residential classes, the OCA retorts that, because the Company has much fewer wastewater customers (63,869) to non-fire water customers (415,059), most water customers do not rely upon the Company's wastewater operations and there is no reasonable basis for a particular class of water customers to have to subsidize the same class of wastewater customers. OCA R. Exc. at 19-20 (citing OSBA Exc. at 17-20; OCA St. 4-R at 10-11).

Further, the OCA counters that the OSBA's proposal results in the Residential class being assigned a larger relative percentage of Act 11 subsidy revenues than the system average, while the Commercial class is assigned significantly less than the system average and the Industrial class is not assigned Act 11 subsidy responsibility. The OCA elaborates that, because the Residential, Commercial, and Industrial class indexed RORs are all reasonably close to unity, when the OSBA's initial class revenue allocations (prior to the Act 11 revenue shift) are combined with the Act 11 revenue increases, the OSBA's recommendation unreasonably favors the Commercial class. OCA R. Exc. at 20 (citing OCA St. 4R at 9-10).

g. OSBA Exception No. 4 and Replies

In its Exception No. 4, the OSBA submits that Aqua's proposal to scale back the Company's proposed revenue allocation must be rejected. The OSBA contends that, although the ALJ acknowledged that the exclusion of wastewater rates from any scale back in this proceeding will reduce Aqua's Act 11 revenue requirement, the ALJ did not discuss how the Company's allocation of its proposed Act 11 revenue requirement of approximately \$20.8 million for water classes should be scaled back to the ALJ's recommended level of approximately \$10.2 million. OSBA Exc. at 20-21 (citing R.D. at 91, Table Act 11; Aqua M.B. at 265; OSBA Exh. BK-1 W, Sch. BK-6W). In order to ensure that the Company's Commission-approved revenue requirement is recovered from water customers on a revenue neutral basis, the OSBA recommends that the Commission: (1) scale back the wastewater class revenue requirements proportionately to reflect the Company's total approved wastewater revenue requirement level; and (2) subtract the Company's approved level of wastewater revenues, by class, from the adjusted wastewater class revenue requirement levels. OSBA Exc. at 25 (citing OSBA St. 1 at 18-19). The OSBA submits that its recommended water service and Act 11 scale-back proposals are consistent with *Lloyd* and Act 11 and would ensure that the Aqua's approved Act 11 revenue requirement would be recovered from water customers on a revenue neutral basis, by customer class. OSBA Exc. at 25.

The OSBA repeats its argument that the Company's proposed scale back of its proposed revenue allocation must be rejected because: (1) the Company's proposed revenue allocation is not cost based and, therefore, using it as a starting point for any scale back is not valid; and (2) a separate scale back is necessary for reductions in the Company's allowed water service revenue requirement and changes in the Company's Act 11 revenue requirement. OSBA Exc. at 21-22 (citing OSBA St. 1-R at 8-11). The OSBA maintains that if the Commission awards the Company a water service revenue increase that is less than Aqua's requested amount and exclusive of Act 11 considerations, then the OSBA's recommended class increases for water service should be proportionately scaled back. OSBA Exc. at 22-23 (citing OSBA M.B. at 19-20; OSBA Exh. BK-1 W, Sch. BK-4W). Thus, the OSBA maintains its position that whatever the Act 11 revenues that the Commission decides to assign to water classes should be subject to a separate scale back, as determined by the level of Aqua's awarded wastewater revenue requirement and the overall level of final wastewater rates. OSBA Exc. at 23-24 (citing OSBA St. 1 at 12, 19; OSBA Exh. 5-B, part 1; OSBA Sch. BK-6WW).

In reply to the OSBA's position that the Commission reject the Company's proposed scale back for water rates for the same reasons that it opposed the Company's water revenue allocation, Aqua contends that the Company has demonstrated that its proposed scale back was reasonable, and therefore, the OSBA's exception regarding this matter should be rejected. Aqua R. Exc. at 10 (citing OSBA Exc. at 20; Aqua R.B. at 107-108; Aqua M.B. at 265-66).

In its Replies, I&E submits that it agrees with the ALJ's recommendation to adopt the I&E methodology for allocating revenue and designing wastewater rates, including I&E's recommended Act 11 subsidy. I&E also agrees that no scale back of Aqua's proposed wastewater rates should be permitted until the entire wastewater Act 11 subsidy allocation is eliminated. I&E R. Exc. at 22 (citing OSBA Exc. at 20-21; R.D. at 88, 91).

h. Aqua LUG Exception No. 1 and Replies

In its Exception No. 1, Aqua LUG disagrees with the ALJ's reliance on the testimony provided by Aqua and the OCA that alleged that Aqua LUG's proposed revenue allocation would result in an unacceptable RROR. According to Aqua LUG, the ALJ never addressed the unfavorable RROR effects that her recommended revenue allocation would have on Commercial customers and the very limited progress that would be made towards cost of service rates for the other classes. Aqua LUG Exc. at 2 (citing R.D. at 93). In this regard, Aqua LUG requests that the Commission adopt its revenue allocation proposal that it developed consistent with *Lloyd,* to determine the reasonableness of the movement towards cost of service. Aqua LUG Exc. at 2-3 (citing *Lloyd*; *Pa. PUC v. Philadelphia Gas Works*, Docket No. R-2008-2073938 (Order entered March 26, 2009)).

More specifically, Aqua LUG asserts that the Company's proposed movement of the Commercial rate class closer to the Company's cost to serve, from a current RROR of 1.07 to 1.05 RROR, would not achieve sufficient movement for the Residential customer class because the resulting RROR under current residential rates would be 0.96 and would not move towards the system average increase in the Company's proposed revenue allocation. Aqua LUG Exc. at 2-3 (citing Aqua M.B. at 9; Aqua LUG St. 1 at 4). Aqua LUG maintains that its recommendation would require the Company to modify its revenue allocation so that: (1) the Residential class RROR would move from 0.96 to 0.98; (2) the Commercial class RROR would move from 1.04 to 1.02; (3) the Industrial class RROR would move from 0.93 to 0.99; and (4) the Public class

RROR would move from 1.18 to 1.15.[74] Aqua LUG Exc. at 3-4 (citing Aqua LUG M.B. at 9-10). Aqua LUG further contends that the basis for its recommendation is the unreasonableness of setting rates that preserve substantial interclass subsidies for the Commercial class (*i.e.*, the Commercial class RROR decreasing from present to proposed rates by 0.02) while not progressing towards cost of service for the Residential class (*i.e.*, the Residential RROR at present and proposed rates remaining at 0.96). Aqua LUG Exc. at 4-5. Moreover, Aqua LUG argues that, given that the Residential class has a RROR of 0.96 under present rates, it is not clear how a reasonable movement towards cost of service justifies a rejection of Aqua LUG's proposed revenue allocation. Aqua LUG adds that, by not immediately moving the Residential customer class to cost of service, Aqua LUG's recommended movement for the Residential class incorporates principles of gradualism. Aqua LUG Exc. at 5 (citing Aqua LUG M.B. at 9-10).

Accordingly, Aqua LUG requests that the Commission reject the ALJ's recommendation and direct the Company to implement the revenue allocation modifications submitted by Aqua LUG because its proposed allocations would move all customer classes closer to their cost to serve. In the alternative, Aqua LUG requests that the Commission adopt the OSBA's recommendation. Aqua LUG Exc. at 2, 6.

Next, Aqua LUG excepts to the ALJ's decision to adopt Aqua's class allocation methodology based on her determination that the Company's proposal does not attempt to exclude the Act 11 allocation from its analysis. More specifically, Aqua LUG takes issue with the discussion in the Recommended Decision where the ALJ accepted the OCA's observation that Aqua LUG's recommendation does not incorporate the subsidization of wastewater operations by water operations. Aqua LUG Exc. at 5 (citing

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[74] Aqua LUG notes that it remains unopposed to the OSBA's proposed alternative revenue allocation that is also intended to adjust the Company's proposed revenue allocation by advancing various customer classes towards their cost of service. Aqua LUG Exc. at 4 (citing Aqua LUG St. 1-S at 2).

R.D. at 92). Aqua LUG submits that the ALJ's discussion lacks the appropriate context, explaining that the ALJ adopted I&E's scale-back recommendation to eliminate the subsidy to wastewater customers prior to proportionately scaling back the additional rates. Aqua LUG Exc. at 5-6 (citing R.D. at 91). Aqua LUG contends that, to the extent I&E's recommendation is adopted by the Commission, any further accounting consideration of the Act 11 subsidy would be a double count. Aqua LUG Exc. at 6. Therefore, Aqua LUG submits that, if the Commission accepts I&E's scale-back proposal to eliminate the subsidy to water customers first, then the Commission should scale back the additional water rates, consistent with Aqua LUG's proposed revenue allocation. *Id.* at 6.

Finally, Aqua LUG argues that without the I&E scale-back recommendation, the legislative authority to allocate a portion of the wastewater cost of service to water customers should not supersede the Commission's evaluation of the water revenue allocation. Aqua LUG notes the OSBA's observation that Act 11 revenue requirements are assigned on a revenue-neutral basis and do not reflect class cost of service. Aqua LUG Exc. at 6 (citing OSBA St. 1-S at 6-7). Therefore, Aqua LUG contends that pursuant to *Lloyd*, the appropriate Act 11 subsidy should be determined after establishing the appropriate water system revenue allocation on a cost of service basis. Aqua LUG Exc. at 6.

In its Replies, Aqua argues that Aqua LUG's exception should be denied because the ALJ correctly rejected Aqua LUG's proposal to move a portion of the industrial class increase to the Residential class, due to a larger increase to blocks 5 and 6 of the consumption rates for the industrial class. Aqua R. Exc. at 10-11 (citing Aqua LUG Exc. at 2-6; Aqua M.B. at 229-30).

In its Replies, the OCA argues that the Commission should reject Aqua LUG's adjustments because Aqua LUG's proposals would move classes by small percentage increments and do not reflect the lack of accuracy of the underlying cost allocations, among other complexities in this case. Therefore, the OCA contends that the ALJ properly concluded that the Company's proposed allocation of class revenues is more appropriate. OCA R. Exc. at 19 (citing Aqua LUG Exc. at 2-6; R.D. at 93; OCA St. 4-R at 12).

i. Masthope Exception No. 2 and Replies

In its Exception No. 2, Masthope argues that the ALJ's adoption of the Act 11 subsidy adjustments results in unjust and unreasonable rates that disproportionately and negatively affect Masthope wastewater customers, particularly commercial customers. Masthope Exc. at 10-11 (citing R.D. at 84-91). Masthope explains that it expressed its concern throughout this proceeding about allocating water revenues to the Company's wastewater revenue requirement which may result in large rate increases to wastewater rates for Masthope customers and, therefore, urged the ALJ to adopt Aqua's original distribution of the proposed rate increases between and within water and wastewater rate schedules. Masthope Exc. at 10 (citing Masthope M.B. at 19-24). Notwithstanding its concerns, Masthope avers that the ALJ ultimately adopted I&E's proposed Act 11 revenue allocation methodology that would result in large increases in Masthope's wastewater usage rates (147% increase) and monthly service charge (35% increase). Masthope Exc. at 10 (citing R.D. at 84-91; Masthope R.B. at 6-7; Masthope M.B. at 19-24). Thus, Masthope requests that the Commission reverse the ALJ's recommendation to the extent it results in dramatic rate increases for Masthope water customers. Masthope Exc. at 10-11.

Masthope also argues that although Act 11 provides the Commission has broad discretion to allocate wastewater revenue requirements across a utility's combined customer base, the Commission should: (1) assure just and reasonable rates for all classes of customers, pursuant to Section 1301 of the Code, 66 Pa. C.S § 1301; (2) avoid rate shock; and (3) embrace the principles of gradualism. Masthope Exc. at 11 (citing 66 Pa. C.S. § 1311(c); *Implementation of Act 11 of 2012*, Docket No. M-2012-2293611 (Order entered August 2, 2012)). Further, Masthope maintains that the impact on its community would be especially detrimental to the unique mix of part-time/seasonal residents and residential and commercial customers. Moreover, Masthope asserts that, if the Commission approves revenues in amounts less than the Company originally proposed, then the Commission should distribute any increased revenue requirement for water and wastewater customers and the amount of revenue support to be provided by water customers in a manner consistent with the Company's proposal. Furthermore, Masthope avers that the Commission should distribute any increase in rates, both between and within rate schedules, in a manner consistent with the Company's original proposal. Masthope explains that Aqua selectively proposed increases between and within rate schedules to encourage its long-term plan of rate schedule consolidation into a uniform tariff. Masthope details that by contrast, the adjustments adopted by the ALJ are excessive for certain customers in specific schedules, including commercial customers in wastewater Zone 6 who would experience as much as a 147% rate increase. Masthope Exc. at 11-12 (citing Masthope M.B. at 19-23).

In its Replies, Aqua notes that it does not oppose Masthope's Exception, explaining that Masthope supports Aqua's proposed Act 11 revenue allocation and Masthope's Exceptions lend further support to Aqua's proposed allocation of revenues. Aqua R. Exc. at 11 (citing Masthope Exc. at 10-11; Aqua R.B. at 99).

In its Replies, I&E argues that although it understands Masthope's argument, any Act 11 subsidy imposed on Aqua's water customers is for the benefit of Aqua's wastewater customers, including Masthope. I&E explains that absent the Act 11 subsidy from wastewater to water customers, the Masthope wastewater rates would have to be further increased. Further, I&E notes that in similar Commission cases, the ALJ and the Commission must balance the justness and reasonableness of all revenue allocation and rate design components, within the complexities of a cost of service methodology, among all customer classes. Moreover, I&E asserts that as a result of making the required choices, ultimately all customer classes will be adversely affected. Therefore, I&E submits that it supports the ALJ's recommendation that the Commission adopt I&E's methodology for allocating revenue and designing wastewater rates, including I&E's recommended Act 11 subsidy. I&E R. Exc. at 24-25 (citing Masthope Exc. at 10-11; R.D. at 82-91).

In its Replies, the OCA refers to its argument that Aqua's Exception No. 9 regarding the Act 11 subsidy should be rejected, to contend that Masthope's objection to decreasing the subsidy for Masthope (one of the legacy systems) should be rejected for the same reasons. OCA R. Exc. at 17 (citing Masthope Exc. at 10-12; R.D. at 88; OCA R.B. at 51-53).

4. Disposition

At the outset, we will address I&E's Exception No. 2. Based on our review, we agree with I&E that the Commission should rely on the wastewater increases by class which were updated in Mr. Kubas' surrebuttal testimony. *See* I&E Exh. 5-SR, Sch 1 at 1. Therefore, we shall grant I&E's Exception No. 2 and strike the table presented in the Recommended Decision at the top of page 88 and replace it with the table set forth in I&E Exhibit 5-SR, Schedule 1, Page 1 of 3, as reproduced below:

I&E Exhibit No. 5-SR
Schedule 1
Page 1 of 3

Aqua Pennsylvania, Inc
R-2021-3027386 Schedule "WW-A" PSW Cost of Service Study
Zones 1 through 6 and Zones 7 through 11 and Grand Total for Aqua Wastewater

	Zone	Cost of Service	Percent	Act 11 *	Percent	Adjusted Cost of Service	Revenue Present Rates	Revenue Proposed Rates	I&E Increase	Percent Increase	I&E Adjustment	Company Increase **	I&E Subsidy
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)*	(M)
	Zones 1-6												
1	Residential	$27,146,216	79.3%	($11,076,966)	82.4%	$16,069,250	$13,419,396	$17,942,695	$4,523,299	33.7%	$1,887,342	$2,635,957	-$9,189,624
2	Non Residential	$7,066,927	20.7%	($2,361,992)	17.6%	$4,704,935	$3,976,095	$5,365,264	$1,389,169	34.9%	$656,907	$732,262	-$1,705,085
3	Third Party	$1,388,690		$0		$1,388,690	$1,280,031	$1,437,920	$157,889	12.3%	$381	$157,508	$381
4	Total Sales	$35,601,833	100.0%	($13,438,958)	100.0%	$22,162,875	$18,675,522	$24,745,879	$6,070,357	32.5%	$2,544,630	$3,525,727	-$10,894,328
5	Contract	$312,754		$0		$312,754	$312,754	$331,801	$19,047	6.1%	$0	$19,046	$0
6	Late Payment	$23,436		$0		$23,436	$23,436	$31,054	$7,618	32.5%	$7,618	$0	$7,618
7	TOTALS - Zone 1-6	$35,938,023		($13,438,958)		$22,499,065	$19,011,712	$25,108,734	$6,097,022	32.1%	$2,552,248	$3,544,773	-$10,886,710
8	Zone 7	$9,925,668		($2,974,708)	-30.0%	$6,950,960	$3,969,765	$6,945,307	$2,975,542	75.0%	$6,665	$2,968,877	-$2,968,043
9	Late Payment						$8,808	$15,410	$6,602	75.0%	$6,602	$0	$6,602
10	Zone 8	$1,831,445		($457,466)	-25.0%	$1,373,979	$998,190	$1,599,095	$600,905	60.2%	$242,526	$358,379	-$214,940
11	Late Payment						$16,378	$26,237	$9,859	60.2%	$9,859	$0	$9,859
12	Zone 9	$10,316,073		($514,835)	-5.0%	$9,801,238	$7,238,362	$11,311,729	$4,073,366	56.3%	$1,532,060	$2,541,306	$1,017,225
13	Late Payment						$20,377	$31,844	$11,467	56.3%	$11,467	$0	$11,467
14	Zone 10	$5,830,936		($1,746,595)	-30.0%	$4,084,341	$2,916,336	$4,440,845	$1,524,509	52.3%	$366,658	$1,157,851	-$1,379,937
15	Late Payment						$7,435	$11,322	$3,887	52.3%	$3,887	$0	$3,887
16	Zone 11	$5,622,603		($1,686,363)	-30.0%	$3,936,240	$2,871,704	$4,246,926	$1,375,222	47.9%	$304,027	$1,071,195	-$1,382,336
17	Late Payment						$17,382	$25,706	$8,324	47.9%	$8,324	$0	$8,324
18	TOTALS - Zone 7-11	$33,526,725		($7,379,967)		$26,146,758	$18,064,737	$28,654,421	$10,589,684	58.6%	$2,492,076	$8,097,608	-$4,887,891
19	WW TOTALS	$69,464,748		($20,818,925)		$48,645,823	$37,076,449	$53,763,155	$16,686,705	45.0%	$5,044,324	$11,642,381	-$15,774,601
20	I&E Proposed Change in Subsidy			($5,044,324)			$20,380	$110,519	$40,139	57.0%	Late Payment Revenue Zones 7-11		

* Column D Adjusted to Match Aqua Exhibit 1-A(a) Schedule Act 11
** Column L Adjusted to Match Aqua Exhibit 5B-B

As will be discussed, at length, below, after our review of the Exceptions and Replies, we agree with the ALJ that Aqua's allocations of revenue between all water customer classifications and all wastewater customer classifications are reasonable and should be approved. We also agree that I&E's methodology for allocating the Act 11 wastewater revenue subsidy should be approved. Table Act 11, which is included in the Commission Tables Calculating Allowed Revenue Increase attached to this Opinion and Order, sets forth the water and wastewater revenue requirement summary for Aqua, based on I&E's allocation methodology.

Additionally, we support the ALJ's recommended adjustment to reduce the gross wastewater revenue requirement to a net basis when shifting the wastewater revenue requirement to water customers.[75] Finally, we agree with the ALJ that any scale back of water rates will first reduce the Act 11 allocation.

To recap, the allocation of revenue among a utility's rate classes involves, *inter alia*, consideration of ratemaking policy and the principles of gradualism. Here, Aqua proposed revenues to be allocated to each customer classification that would be required to move that classification toward the cost of providing service (or revenue requirement). R.D. at 84-85 (citing Aqua St. 5 at 10, 21; Aqua Exh. 5-A, Part I, Sch. A; Aqua Exh. 5-B, Part I, Sch. WW-A). Additionally, Aqua proposed to recover a shortfall of approximately 30% of the Company's proposed revenue requirement from wastewater revenues in water rates. R.D. at 85; Aqua M.B. at 216. I&E, the OCA, the OSBA, and Aqua LUG all opposed Aqua's Act 11 subsidy proposal and proposed alternative Act 11 subsidy reduction methodologies. R.D. at 87-89; Aqua LUG M.B. at 7, 9-10. The ALJ recommended I&E's methodology and agreed with I&E and the Company that any scale back of water rates should reduce the Act 11 allocation first. The ALJ reasoned that

[75] We note that, as outlined in Table Act 11, this will result in the Company's overall allowed revenue requirement being reduced by approximately $77,706 after the Act 11 Allocation.

I&E's approach, *inter alia*: (1) considers the number of water and wastewater customers in each system; (2) balances the goal of aligning rates with the cost of service while mitigating some of the large rate increases that would result absent an allocation of wastewater revenue; and (3) acknowledges the benefits received by the communities serviced by the acquired systems. R.D. at 91.

In its Exceptions, Aqua argues that it demonstrated that justifications and arguments advanced by I&E and discussed by the ALJ were unreasonable and unsupported by record evidence, and that the ALJ misrepresented and/or ignored the testimony and exhibits presented by the Company in support of its proposed wastewater rate design. Similarly, in its Exceptions, the OSBA argues that the ALJ adopted the I&E's recommended wastewater rate design and rate increases without providing details regarding the allocation of Act 11 wastewater subsidies to water customers. We disagree with the arguments expressed by Aqua and the OSBA on these matters. In our view, the ALJ appropriately reasoned that the Company did not present sufficient evidence to demonstrate that allocating 30% of the proposed wastewater requirement to water customers is reasonable and in the public interest. Further, the ALJ appropriately found that shifting 30% of the wastewater revenue requirement to water customers is not equitable and will not result in just and reasonable rates. Indeed, we agree with the OCA's position in its Replies to Exceptions that it is not reasonable or in the public interest for those water customers who do not receive a benefit from wastewater operations or Section 1329 acquisitions to support a disproportionate share of the revenue requirement driven by such acquisitions. With regard to Aqua's and the OSBA's arguments that the ALJ did not provide sufficient analysis in her discussion, we disagree. The ALJ was aware of the positions and arguments put forth by the Company and the OSBA, including the testimonies and exhibits submitted in support of their positions. However, the ALJ has the discretion to determine whether, and to what extent, further discussion and analysis is warranted. Here, it appears that the ALJ did not believe that further consideration of these matters was necessary to recommend that I&E's proposed wastewater allocation methodology be approved. Accordingly, we will deny Aqua Exception No. 9 and OSBA Exception No. 3.

The OCA also filed Exceptions arguing that its method for allocating a portion of the wastewater revenue requirement to water customers is more reasonable because it considers the FMV premium paid for each acquired system. We agree that a portion of wastewater customers benefitted from the revenue generated by the 1329 acquisition; however, we also agree with the ALJ's reasoning that I&E's approach for allocating the wastewater revenue requirement and designing wastewater rates is less complex than the method offered by the OCA. Indeed, I&E's approach is more streamlined than the methods advanced by the other Parties, while also addressing the benefits received by the communities serviced by the acquired systems and moving rates toward their respective cost of service. Similarly, with regard to the scale-back approach, both the OCA and the OSBA contest the ALJ's adoption of the scale-back approach; however, we are of the opinion that the scale back agreed upon by Aqua and I&E offers a less complicated method than other alternatives. Therefore, we agree with the ALJ's conclusion that any scale back of water rates will first reduce the Act 11 allocation. Accordingly, we will deny the OCA's Exception No. 11 and the OSBA's Exception No. 4.

The OSBA also filed Exceptions challenging the ALJ's reasoning and submitting that the OSBA's proposed water revenue allocation should be adopted. The OSBA is of the opinion that the ALJ violated *Lloyd*, misapplied Section 1311, and ignored Commission precedent by reasoning that Aqua's methodology better reflects cost of service and concluding that the Company's allocation of revenues is reasonable. We disagree with the OSBA. We are of the opinion that reasons considered by the ALJ upon which she based her recommendation to approve the Company's allocations of revenues between all water and wastewater customer classifications are just, reasonable, and in the public interest, and should be approved. The OSBA's contention is that Aqua's proposed revenue allocation, which views cost of service as a whole and does not exclude the Act 11 allocation, conflicts with the requirement in *Lloyd* that the basis for individual utility service rates is specific to each service's cost of service. We find this argument unpersuasive. As noted by Aqua in its Replies, the OSBA's reliance upon *Lloyd* appears to be misplaced as wastewater costs are not stand-alone, separate rates charged to water customers. Therefore, we do not believe that the principles of *Lloyd* have been violated. The OSBA also argues that its proposed water revenue allocation correctly isolates the Act 11 allocation. We disagree. Rather, we find the ALJ's conclusion, that the Company's methodology better reflects the cost of service because Aqua's proposed allocation views cost of service "as a whole" and moves each customer classification toward its appropriate cost of service, is more persuasive and in the best interest of the public. R.D. at 92. Accordingly, we shall deny the OSBA's Exception Nos. 1 and 2.

In its Exceptions, Aqua LUG argues that the ALJ erred in adopting the Company's revenue allocations rather than the revenue allocations proffered by the OSBA and itself. Aqua LUG opines that the ALJ's recommendation is baseless and will delay progress of the movement of all customer classes towards their cost of service and result in an unfavorable RROR for Commercial customers. As discussed above, we agree with the ALJ's reasoning and basis for recommending that the Company's allocation of revenues between all water and wastewater customer classifications be approved. Accordingly, we will deny Aqua LUG's Exception No. 1.

Finally, in its Exceptions, Masthope disagrees with the ALJ's adoption of the Act 11 subsidy adjustments because they will disproportionately affect Masthope's wastewater customers. As discussed by the ALJ, it is not fair to the Company's water customers to mitigate increases in expenses to repair acquired systems and to take on the shortfall between the cost of service to serve the wastewater systems. I&E's approach for allocating wastewater revenue and designing wastewater rates allows for each service to recover as much of the cost of providing that service as possible without removing the subsidy, which would result in large increases for every customer. R.D. at 88, 90. Indeed, we agree with I&E's position in its Replies to Exceptions that Masthope's rates would have further increased without the Act 11 subsidy from wastewater to water customers and, as a result of balancing the justness and reasonableness of all revenue allocation and rate design components with the inherent complexities of a cost of service methodology, all customers will ultimately be affected. Therefore, although we understand Masthope's point of contention, we will deny Masthope's Exception No. 2.

D. Tariff Structure and Rate Design

A utility's rate structure implements the Commission's approved revenue increase to determine how the overall increase will be allocated among the utility's various customer classes. Once a class revenue allocation is determined, development of a rate design will address how the tariffed rates and rate elements will generate the allocated revenues. I&E noted the following unique rate structure and rate design challenges present in this proceeding: (1) water base rates; (2) an Act 11 subsidy applied to water base rates to subsidize wastewater customers; (3) wastewater base rates; (4) new rate zones for numerous Section 1329 acquisitions; and (5) third-party sales rates. I&E R.B. at 49. Under the Company's proposal, a residential water customer in the Main Division of Rate Zone 1, using 4,000 gallons of water per month,[76] would experience a monthly bill increase from $69.35 to $81.32, or 17.3% per month, and residential customers in other water divisions would experience increases ranging from 17.3% to 51.3%. *See* Aqua Exh. 5-A, Part II, Sch. 8.[77] Wastewater customers would see increases

[76] The Company claimed that the average usage of 4,000 gallons per month is substantiated in the Company's prior rate case as the pre-COVID pandemic average residential usage was 4,068 per month for the residential class. Aqua St. 5-R at 14.

[77] Present Rates include 7.5% DSIC.

ranging from 7.9% to 84.87%, with one division seeing a proposed decrease (Rate Zone 5 – Newlin Green). *See* Aqua Exh. 5-B, Part II, Sch. WW-7.[78]

1. Positions of the Parties

a. Water Rate Design

(1) Aqua's Water Rate Design Proposal

As shown in Table 8, below, the majority of Aqua's water rate divisions are grouped into three rate zones (Rate Zones 1-3) based on the similarity of their rate structure and rate design, while the Bunker Hill, Sun Valley, Phoenixville, and Belle Aire Acres Divisions are displayed separately because they are dissimilar from those divisions grouped into Rate Zones 1-3.

The majority of Aqua's water customers are charged the rates applicable to its Main Division, designated as Rate Zone 1. The Company proposed to continue to move rate divisions closer to each other and to the Rate Zone 1 in order to facilitate further consolidation with the Main Division. Aqua St. 1 at 29. Specifically, Aqua's proposal indicated that it is working to consolidate water rates for Rate Zones 1 and 2 (with the exception of Chalfont, Concord Park and Treasure Lake in Rate Zone 2). Aqua's witness, Ms. Heppenstall, explained that the Company developed the following five guidelines for the design of water rates: (1) maintain separate rate divisions for those areas with year-round usage and those areas with seasonal usage; (2) maintain a low-use block for the residential class at 2,000 gallons per month in each division, and a sixth block for the industrial classification for usage over 10 million gallons per month; (3) continue movement of those areas with year-round usage toward the Main Division

[78] Present Rates include 5.0% DSIC.

rates; (4) increase existing Main Division private fire service line rates 17.5% and private hydrant charges by 20.6%; and (5) increase the existing Public Fire Hydrant rate up to the 25% of cost of service level. *See* Aqua St. 5 at 11.

Water Operations - Rate Zones / Divisions

Rate Zone	Divisions
Rate Zone 1	Main Division Country Club Gardens and Sand Springs Division Beech Mountain Division Bristol Township Division Mifflin Township Division Mount Jewett Division Robin Hood Lakes Division
Rate Zone 2	Superior Division Chalfont Division Concord Park Division Treasure Lake Division
Rate Zone 3	Oakland Beach Division CS Water (Masthope) Division Eagle Rock Division
	Bunker Hill Division Sun Valley Division Phoenixville Division Belle Aire Acres Division (Receivership)*

* The James Black Water Service Company – Belle Aire Acres Development is being operated by Aqua under a Receivership established via Commission Order on September 3, 2019 at Docket No. M-2019-3012563. Aqua began its Receivership on September 11, 2019 and will continue to act as Receiver for the system until a final determination is made by the Commission. Belle Aire Acres customers are flat rate unmetered customers.

Table 8: Aqua's water operations showing its Division by Rate Zone

As explained by the OCA's witness, Mr. Glenn A. Watkins, Aqua's rate design proposal pertaining to its water operations generally consisted of: (1) the continued movement of those areas with year-round usage toward the Main Division rates; (2) the continuation of its inverted-block usage rate structure; and (3) an increase to its monthly fixed customer charges. The Company's present and proposed water rates by class, set forth in Schedule I of Aqua Exhibit 5-A, Part I, reflect its rate structure, rate design and the distribution of the increase in revenue proposals in this proceeding.[79]

Table 9, below, provides a summary of the Company's current and proposed 5/8" meter residential customer charges:

Aqua Water
Current & Proposed Residential 5/8" Customer Charges

Rate Zone	Division	Current	Proposed	Percent Change
1	Main	$18.00	$22.40	24.44%
2	Main	$18.00	$22.40	24.44%
3	Main	$28.00	$32.40	15.71%
BH	Bunker Hill	$8.00	$11.80	47.50%
PH	Phoenixville	$3.33	$4.90	47.15%

Table 9: Summary of Aqua's current and proposed customer charges by Rate Zone for residential 5/8" meter water customers. OCA St. 4 at 13.

79 Ms. Heppenstall provided updates to her revenue allocation and rate design for water service in Aqua Exhibit 5R-A, Part I, as part of her rebuttal testimony. The Company's revised revenue exhibits reflect corrections to: (1) the 6-inch and 8-inch private fire rates in the Superior Division, and (2) Aqua's public fire revenue under proposed rates. *See* Aqua Exh. 5R-A, Part I, Schs. 1 and 7A.

Aqua indicated that its proposal includes increases in consumption charges so that revenues by class move toward cost of service indicators and to recover the total revenue requirement. Aqua St. 5 at 12.

The Company explained its proposed rates for the remaining non-seasonal water divisions as follows:

> Zone 1 – CC Garden, Sand Springs, Mifflin Township, Mount Jewett, and Robin Hood rates will move fully to Rate Zone 1 rates. Beech Mountain and Bristol Township division rates will continue to move toward Zone 1 rates.
>
> Zone 2 – will move fully to rates in Rate Zone 1 by raising the meter charges for ¾-inch to 4-inch to the level of Rate Zone 1 rates. All other rates were previously equal to Zone 1 rates.
>
> Two other areas, Bunker Hill and Phoenixville, rates were increased to move toward Zone 1 rates. The Company capped the rate increases for these two areas to 48%.

Aqua St. 5 at 12.

The Company explained its proposed rate structure for seasonal areas as follows:

> The Zone 3 Division has a significant number of seasonal customers and will continue to be served under the merged seasonal rate design. The customer charge is increased to $32.40 per month, but is offset with a lower first block consumption rate than Main Division for the first 4,000 gallons. The bills for the seasonal rate structure are equalized with Main Division at the 4,000 gallon average per month and greater consumption levels.

Aqua St. 5 at 13.

The Company further explained its use of competitive service riders[80] and summarized the development of its rate proposals regarding public and private fire and those for Industrial Standby Rates, Resale, and Electric Generation Standby Rates. *See* Aqua St. 5 at 13-15; Aqua M.B. at 232-33.

(2) I&E

As previously discussed, Aqua proposed to subsidize its wastewater revenue requirement by approximately $20.8 million with increased water revenues by the same amount under Act 11. Aqua Exh. 1-A(a), Sch. Act 11. Although the actual recommendations differ, I&E, the OCA, and the OSBA[81] each recommended a reduction to the requested subsidy from Aqua water customers, indicating a reflection of that reduced subsidy through a corresponding increase to the wastewater rates proposed by the Company.

Therefore, I&E's recommended water rate design changes are based upon its proposal to reduce the Act 11 subsidy from water customers. Specifically, I&E proposed a 20% increase for water customers as compared to the Company's proposal for water customers. Thus, I&E asserted that the Company's proposed percentage increases to the water customer classes should all be scaled back to 20% of the Company's original proposed percentage increases. I&E M.B. at 73. I&E explained that this scale back of water rates, including customer charges, should be proportional to the percentage increase originally proposed by the Company. I&E St. 4 at 18-20.

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[80] The Company noted that it has not proposed any changes to its competitive service riders in this proceeding. Aqua M.B. at 232.

[81] "As a result of the OSBA's proposal to assign additional increases, in aggregate, of $2.259 million to the Company's Base and New Garden Divisions, Mr. Kalcic testified that the OSBA's overall proposed wastewater increase is $13.8 million or 37.3%, and its recommended Act 11 revenue requirement is $18.580 million, or $2.259 million less than Aqua's proposal." OSBA St. 1 at 16-17.

(3) OCA

Although the OCA did not agree with I&E's methodology, the OCA did agree that the wastewater subsidy should be reduced. Therefore, the OCA's recommended water rate design changes are also based upon its proposal to reduce the Act 11 subsidy from water customers. Specifically, the OCA recommended to reduce the Company's proposed Act 11 water subsidization of approximately $20.8 million by $9.065 million. Accepting the Company's proposed water increases by division and class, the OCA allocated the $9.065 million to each division and class on a prorated basis. OCA St. 4 at 11.

Additionally, the OCA contended that Aqua's proposed increase to water customer charges was unsupported and that certain overhead costs were improperly included in the Company's customer cost analysis. Specifically, according to the OCA, Aqua included indirect O&M expenses, indirect depreciation expenses and indirect rate base within its customer cost analysis. OCA M.B. at 99-101.

Based on the customer cost analyses performed by its witness, Mr. Watkins, the OCA argued that there is no reasonable basis for Aqua's proposal to increase the existing monthly residential water customer charges in the Main Division of Zone 1 ($18.00), Zone 2 ($18.00) and Zone 3 ($28.00) above current rates.[82] OCA St. 4 at 16. The details of Mr. Watkins' customer cost analyses are presented in OCA Schedule GAW-7. Table 10, below, provides a summary of the OCA's residential customer cost analyses for residential 5/8" meter water customers under the OCA's and Aqua's proposed cost of capital.

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[82] The OCA accepted Aqua's proposed increases to the customer charges for Bunker Hill and Phoenixville because the current rates and proposed rates are significantly lower than the current Main Division rates. OCA St. 4 at 16.

Aqua Water Residential Customer Costs (5/8" Meter Equivalent)		
	OCA Proposed Cost of Capital	Aqua Proposed Cost of Capital
Direct Costs	$17.07	$19.26
Direct + Indirect Costs	$17.36	$19.55

Table 10: Summary of results of the OCA's residential customer cost analyses (OCA Schedule GAW-7) for residential 5/8" meter water customers under the OCA's and Aqua's proposed cost of capital. *See* OCA St. 4 at 16.

Aqua contended that the OCA's attempt to exclude certain costs from the calculation of the residential water customer charge lacks merit and undermines the support provided by Aqua for its proposed residential water customer charges. Aqua M.B. at 234-35. Aqua specifically noted its reliance on Commission precedent in the *Aqua 2004 Order* in the development of its residential customer charge[83] and further averred that the Commission's determination in the *Aqua 2004 Order* was subsequently affirmed in the *2012 PPL Order*. Aqua M.B. at 234-235.

(4) Aqua LUG

Only Aqua LUG addressed the issue of non-residential water charges. Aqua LUG's Main Brief reiterated the arguments it raised in testimony regarding changes to the design of the customer charges and the rates for consumption blocks for commercial and industrial customers. *See* Aqua LUG M.B. at 10-12. Specifically, Aqua LUG's witness, Mr. Baudino, testified that "Commercial and Industrial customer charges

[83] *Pa. PUC v. Aqua Pennsylvania, Inc.*, Docket No. R-00038805 (Order entered August 5, 2004) (*Aqua 2004 Order).*

and the rates for consumption blocks 1 through 4 are the same for both classes," but noted "Industrial class rates also have 5th and 6th blocks that Commercial customers do not have." Therefore, he recommended that the Company keep charges for blocks 1 through 4 of the Commercial and Industrial classes similar, while avoiding "excessive increases for blocks 5 and 6 of the Industrial class." Aqua LUG St. 1 at 5-6. He further recommended that Aqua could shift some of the revenue allocated to the Industrial class to the Residential class to moderate any increases, if necessary. Aqua LUG St. 1 at 6.

Aqua responded to the arguments posed by Aqua LUG, contending that Aqua LUG's proposals are unreasonable and unnecessary. Aqua M.B. at 229-230, 236-237.

b. Wastewater Rate Design

(1) Aqua's Wastewater Rate Design Proposal

Aqua currently has eleven different wastewater rate zones, with different subsystems and eight different third-party customers. *See* Aqua Exh. 5-B, Part II, Schs. WW-2, LMK-3, EB-3, CH-3, EN-2, and NG-2. Since the Company's last base rate proceeding, it has acquired the Limerick, East Bradford, Cheltenham, East Norriton, and New Garden systems through separate Section 1329 proceedings.[84] These five systems became Rate Zones seven through eleven, as shown in Table 11, below:

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[84] *See* Aqua Pennsylvania, Inc. Tariff Sewer – PA P.U.C. No. 2, Original Page 5 through Supplement No. 6 to Tariff Sewer – PA P.U.C. No. 2, Third Revised Page 6.

Wastewater Operations - Rate Zones / Divisions

Rate Zone 1 (Main)	Rate Zone 1A	Rate Zone 1B
Media Division	Treasure Lake Division	Penn Township Division
Bidlewood Division	Village at Valley Forge Division	
Eagle Rock Division	Bunker Hill Division	
Rate Zone 2	**Rate Zone 3**	
Emlenton Borough Division	Beech Mountain Lakes Division	Stony Creek Division
Rivercrest Division	Deerfield Knoll Division	Thornhurst Division
White Haven Division	Laurel Lakes Division	Willistown Woods Division
Pinecrest Division	Links at Gettysburg Division	Woodloch Springs Division
Rate Zone 4	**Rate Zone 5**	**Rate Zone 6**
Honeycroft Village Division	Avon Grove School Division	CS Sewer Division (Masthope)
Lake Harmony Division	East Bradford Division	
New Daleville Division	Little Washington Division	
Peddlers View Division	Plumsock Division	
Tobyhanna Township Division	The Greens at Penn Oaks Division	
Twin Hills Division	Newlin Green Division	
	Sage Hill Division	

Zones Recently Acquired Under Act 129, at 66 Pa. C.S. § 1329

Rate Zone 7 - Limerick Division

Rate Zone 8 - East Bradford Township Division

Rate Zone 9 - Cheltenham Township Division

Rate Zone 10 - East Norriton Township Division

Rate Zone 11 - New Garden Township Division

Table 11: Aqua's wastewater operations showing its Divisions by Rate Zone.

As a result of recent and prior acquisitions of wastewater systems, Aqua's wastewater rates are comprised of several varying rate structures, including fixed customer or EDU[85] charges, plus usage charges, unmetered flat rates, and structures with minimum usage allowances. Aqua proposed a similar model to its water operations for its wastewater operations with the intent of gradually grouping and consolidating divisions towards Rate Zones, specifically proposing to begin (or continue) movement to unified customer charges for metered customers.

Aqua's witness, Ms. Heppenstall, explained that the Company developed the following four guidelines for the design of wastewater rates: (1) move toward additional consolidation of rates across rate zones; (2) for metered areas, develop a rate structure that includes a customer charge or EDU charge and a single block usage charge; (3) for unmetered areas, develop a monthly flat rate equal to 4,000 gallons priced-out at the respective zone rates; and (4) where possible, eliminate an allowance. *See* Aqua St. 5 at 21-22. The Company presented a comparison of its present and proposed wastewater rates in Schedule F-WW of Aqua Exhibit 5-B, Part I.[86]

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[85] The Company's proposed wastewater tariff defines an EDU as follows:

> Equivalent Dwelling Unit or "EDU"**:** The EDU is a measure based upon the estimated average daily wastewater flow for the type of business, as calculated by the Pennsylvania Department of Environmental Protection regulation at 25 Pa. Code § 73.17 divided by the typical estimated average daily wastewater flow from a current single-family unit. In the Company's sole discretion, the Company may assign more than one (1) EDU for a residential Property.

See Tariff Sewer No. 3, Original Page 25.

[86] Ms. Heppenstall provided updates to her revenue allocation and rate design for wastewater service in Aqua Exhibit 5R-B, Part I, as part of her rebuttal testimony. The Company's revised revenue exhibits reflect corrections to: (1) Aqua's proposed unmetered charges for Woodloch Springs, and (2) Aqua's proposed rate for Southdown Homes. *See* Aqua Exh. 5R-B, Part II, Sch. WW-5 at 9 and 17.

In this proceeding, Aqua has proposed the same rates for Zones 1 and 2, and therefore, has merged Zone 2 into Zone 1. The proposed merger of Zone 2 into 1 (with which I&E disagrees) would mean that each subsequent zone could be reclassified up one (*i.e.*, Zone 3 customers would become Zone 2; Zone 4 customers would become Zone 3; Zone 5 customers would become Zone 4; and Zone 6 customers would become Zone 5). *See* Tariff Sewer, Original Page 5 and 6.

Additionally, as part of its consideration of the design of wastewater rates, Aqua performed an analysis of the feasibility of implementing a summer wastewater cap, as required by the settlement of its 2018 base rate proceeding. *See* Aqua Exh. 5-C. Based on this analysis, Aqua witness, Ms. Heppenstall, explained Aqua's contention that it was not appropriate to implement a summer wastewater cap for its wastewater customers:

> [Aqua] performed an analysis based on capping usage at winter water usage levels for the Wastewater Base Operations. This cap would have the affect[sic] of raising the rates for all wastewater customers significantly and benefiting high water users. Our analysis, attached as Exhibit 5-C, shows that, under the cap, billed usage would decline by 38% and the average monthly bill for a residential customer using 4,000 gallons per month would rise to $85.73, a 10.6% increase over the projected bill under proposed filed rates of $77.49. In addition, as the wastewater operations benefit from the shift under Act 11 from wastewater to the water operations, it is conceivable that as wastewater rates rise due to the implementation of the cap, more Act 11 shifting would be needed to mitigate this increase.

Aqua St. 5 at 21-22.

(2) I&E

Consistent with the modifications I&E recommended for the Company's water rate design changes, I&E recommended similar adjustments to Aqua's proposed wastewater rates that are intended to reduce the size of Aqua's proposed Act 11 subsidy of wastewater customers. As such, I&E generally recommended higher rates for wastewater customers than those proposed by the Company, producing a larger increase for each division.[87] I&E provided a comprehensive summary of its proposed wastewater rate structure in its Main Brief that was presented in greater detail by its witness, Mr. Kubas, in his direct and surrebuttal testimony and accompanying exhibits. *See* I&E M.B. at 74-92; I&E St. 5; I&E St. 5-SR. In revising rates in Zones 1 through 6 to reduce the Act 11 contribution related to the wastewater customers in these rate zones, Mr. Kubas proposed the following recommendations shown in Table 12, below.

[87] As previously explained, I&E recommended an increase of $6,097,022 for Rate Zones 1 through 6, as opposed to the Company's $3,544,773 requested increase for those Zones, and an increase of $10,589,684 for Rate Zones 7 through 11, as opposed to the Company's $8,097,608 requested increase for those Zones. *See* I&E Exh. 5-SR, Sch. 1 at 1, Cols. I and L, lns. 7 and 18.

Summary of I&E Recommendation for Rate Zones 1-6

RZ 1:
- Increase the customer charges, unmetered rates and the volumetric charge by 46.8%.
- Increase the Media and Bunker Hill unmetered charge to $90.00/month.
- **39.8% bill increase for an average residential customer.***

RZ 1A and 1B:
- Set these rates equal to Zone 1 rates.
- Eliminate the allowance in Zone 1B.
- **52.2% bill increase for an average residential customer in Zone 1A.***
- **42.5% bill increase for an average residential customer in Zone 1B.***

RZ 2 - Main:
- An across-the-board increase of 46.7% to tariff rates.
- No consolidation of Rate Zone 2 with Rate Zone 1 as proposed by Aqua.
- **39.7% bill increase for an average residential customer.***

RZ 2 - Pinecrest:
- Maintain Aqua's proposed rate design of no increase.

RZ 3 - Main:
- Increase the customer and volumetric charges by 36.6% per month.
- Consolidate the unmetered charges to one charge.
- **29.8% bill increase for an average residential customer.***

RZ 3 - Woodloch Springs (Flat Rate):
- Accepts Aqua's proposed rate structure based upon EDU billing, with no usage charge.
- Increase the monthly unmetered charge to $109.00/month, as opposed to Aqua's proposal of $101.03/month ($109.00 per EDU is the same unmetered charge I&E proposed for Zone 3 - Main customers).
- **52.5% bill increase for an unmeterd commercial customer.**

RZ 4:
- An across-the-board increase of 31.1% to tariff rates.
- **24.9% bill increase for an average residential customer.***

RZ 5:
- Accepts Aqua's proposed rates.
- **20.3% bill increase for an average residential customer in RZ 5 - Main.***
- **4.4% bill decrease for an average residential customer in RZ 5 - Newlin Green.***

RZ 6:
- Increase the customer charge by 41.8%, the usage rate by 160%, and the unmetered rate by 53.5%.
- **44.6% bill increase for an average residential customer.***

* I&E assumed an average 5/8" residential customer using 3,700 gallons per month.

Table 12: Summary of I&E's recommended rate changes for Aqua's wastewater Rate Zones 1 through 6 (*See* I&E Exh. 5, Sch. 2 at 1, Cols. F and L; I&E Exh. 5, Schs. 3-8 at 1, Col. F; *see also*, I&E Exh. 5. Sch. 2 at 2-4, Sch. 3 at 2; Sch. 4 at 2-4: Sch. 5 at 2; I&E Exh. 5-SR, Sch. 2; Aqua Exh. 5-B, Part II, Sch. WW-7 at 11-12; Aqua Exh. 5R-B, Part II, Sch. WW-5 at 9).

As previously indicated, Zones 7 through 11 include the Limerick, East Bradford, Cheltenham, East Norriton,[88] and New Garden systems, which were acquired after the *Aqua 2018 Rate Case*. Some of these systems have rates lower than present rates in Zones 1 through 6, and therefore, I&E argued that it is unfair to keep these rates artificially lower than the rates of existing customers. As delineated in Table 13, below, I&E recommended adjustments to rates in Zones 7 through 11 to reduce the subsidy, simplify the rate structure, and limit the increase to Zone 7 flat-rate customers and certain Zone 11 usage blocks. I&E reasoned that acquiring these systems should not harm existing Aqua customers; therefore, the larger than average increase to rates in Zones 7 through 11, shown on page 3 of I&E Exhibit 5-SR, Schedule 1, balanced out by the benefits to the municipality and/or customers of the acquired systems, will, according to I&E, limit the harm to other Aqua customers by reducing the subsidy paid by other non-Zone 7-11 Aqua customers. I&E noted that it is tempering the proposed increases in order to mitigate the large increases to the monthly customer charges, usage rates, unmetered rates, and average bills for both residential and commercial customers in Zones 7-11. I&E added that it is recommending rates so that the average residential bill increase is limited to generally less than 100%. I&E St. 5 at 35-38.

[88] Aqua acquired the Whitpain system with the East Norriton system on June 19, 2020 at Docket No. A-2019-3009052.

Summary of I&E Recommendation for Rate Zones 7-11

RZ 7 - Limerick:
- Increase the customer charge by 40.6% and the volumetric rate by 33.1%.
- Eliminate the allowance (also proposed by Aqua).
- Increase the unmetered rate to $60.00/month.
- **89.2% bill increase for an average residential customer.***

RZ 8 - East Bradford:
- Monthly customer (EDU) charge of $55.00, as opposed to Aqua's proposal of $39.10.
- Volumetric charge of $1.12/100 gallons.
- Accepts Aqua's proposed monthly commercial customer charge of $39.10.
- **74.2% bill increase for an average Multi-Family Residential customer.***
- **84.3% bill increase for an average commercial customer.**

RZ 9 - Cheltenham:
- Increase the customer charge to $30.00/month (43.6% increase).
- Increase the volumetric charge to $0.68/100 gallons (73.9% increase).
- **56% bill increase for an average residential customer.***

RZ 10 - East Norriton & Whitpain:
- Increase the customer charge to $35.00/month (66.0% increase).
- Increase the volumetric charge to $0.76/100 gallons (16.2% increase).
- Eliminate the allowance (also proposed by Aqua).
- **72.6% bill increase for an average residential customer in RZ 10 - East Norriton.***
- **99.4% bill increase for an average residential customer in RZ 10 - Whitpain.***

RZ 11 - New Garden:
- Increase the customer charge to $43.00/month (14.2% increase).
- Increase the residential volumetric charge to $2.20/100 gallons for usage up to 5,000 gallons/month and $3.1626/100 gallons for usage over 5,000 gallons per month.
- Eliminate the allowance (not proposed by Aqua).
- **81.7% bill increase for an average residential customer.***

* I&E assumed an average 5/8" residential customer using 3,700 gallons per month.

Table 13: Summary of I&E's recommended rate changes for Aqua's wastewater Rate Zones 7 through 11 (*See* I&E Exh. 5, Schs. 6-7 at 1, Cols. F and G; I&E Exh. 5-R, Sch. 2 at 1, Cols. F and G; *see also*, I&E Exh. 5. Sch. 6 at 2, 4, 5, Sch. 7 at 2, 3, 4; I&E Exh. 5-R, Sch. 2 at 2).

With respect to non-residential wastewater charges, only I&E addressed this issue. Specifically, as previously explained, I&E's proposed rate design changes regarding Rate Zone 8 – East Bradford operations were based upon its proposals to reduce the Act 11 wastewater revenue allocation from this Rate Zone to water customers.

Aqua responded to I&E's rate design proposals for wastewater rates, generally opposing the rate design modifications proposed by I&E. In this regard, the Company contended that I&E's proposals would be contrary to the principles of gradualism, resulting in significant percentage increases to an average customer bill, as well as significant dollar-for-dollar increases. *See* Aqua M.B. at 222-23. Aqua particularly noted that I&E's proposed changes to the commercial wastewater customer rates for Rate Zone 8 – East Bradford would increase the average bill by over 84%. Aqua M.B. at 245 (citing I&E Exh. 5, Sch. 6 at 5).

(3) OCA

As he contended with respect to the Company's proposed increase to water customer charges, the OCA's witness, Mr. Watkins, argued that the Company provided no support for its proposed increase to wastewater residential customer charges. OCA St. 4 at 17. Therefore, Mr. Watkins opposed Aqua's proposal to increase the wastewater Rate Zone 1 5/8" monthly residential customer charge by $8.10 per month, from $31.00 to $39.10. OCA St. 4-S at 17. Mr. Watkins argued that similar to Ms. Heppenstall's customer cost analysis for water, her analysis for wastewater also includes numerous overhead costs that cannot be reasonably considered "direct costs" required to connect and maintain a customer's account. OCA St. 4-SR at 7.

Aqua contended that the OCA's arguments it proffered against the approval of the Company's proposed residential wastewater customer charges lack merit and ignore the record evidence provided by Aqua. Aqua M.B. at 238-239. Aqua averred that the OCA's proposal regarding Rate Zone 1 rates should be rejected because, as the Company's witness, Ms. Heppenstall, demonstrated, the weighted average of all wastewater customer charges under proposed rates is lower than the customer charge that the Company can support based upon a customer cost analysis which is summarized in Table 14, below:

Rate Zone	Metered Bills	Customer Charge Revenue*	Average Customer Charge
RZ 1	$ 16,897	$ 660,669	$ 39.10
RZ1A	26,337	1,146,776	43.54
RZ1B	9,833	384,486	39.10
RZ2	11,663	492,629	42.24
RZ3	27,676	1,607,722	58.09
RZ4	8,085	626,580	77.50
RZ5	6,457	607,967	94.15
RZ5 - NG	588	54,957	93.45
RZ6	16,548	829,074	50.10
RZ7	82,876	3,271,931	39.48
RZ8	14,399	562,999	39.10
RZ9	202,241	5,705,208	28.21
RZ10	56,687	1,834,952	32.37
RZ11	25,392	1,361,551	53.62
Total	$ 505,680	$ 19,147,501	$ 37.86

* Under proposed rates.

Table 14: Aqua's summary of its average wastewater customer charge by Rate Zones (Aqua M.B. at 239 (citing Aqua St. 5-R at 11)).

Aqua further asserted that the OCA's rate analysis was "incomplete," and noted that although Mr. Watkins proposed to maintain the existing customer charge of Rate Zone 1, he did not discuss the customer charges for Rate Zones 2 through 6. Aqua St. 5-R at 11, 14.

With regard to Rate Zones 7, 8 and 10, the only area of disagreement between Aqua and the OCA is whether the residential wastewater customer charges should be $31.00, which is the rate recommended by the OCA for residential Rate

Zone 1, rather than the Company's proposed charges of $39.48, $39.10 and $32.37, respectively.[89] Aqua M.B. at 240-41; OCA M.B. at 102-03; OCA St. 4 at 18-19.

With regard to Rate Zone 11, the OCA objected to Aqua's proposal to increase the fixed monthly charge from $37.64 to $51.71 per month and recommended holding it at the current $37.64 level, to avoid moving the charge further from the $31.00 residential customer charge recommended by the OCA for most of the wastewater rate zones. OCA M.B. at 103. Also, similar to I&E, the OCA recommended eliminating the usage allowance. OCA M.B. at 103; OCA St. 4 at 18.

Aqua contended that the OCA's proposals regarding Rate Zones 7 through 11 are similarly meritless. Aqua M.B. at 240-43.

In addition to its recommended modifications to the Company's proposed wastewater rates, the OCA offered further proposals regarding Aqua's unmetered rates. OCA M.B. at 104-108. The OCA's discussion surrounding the rate design of Aqua's metered and unmetered customers centered on its concern that under present rates, the Company's average monthly metered revenue per customer, for all customers, is different than the Company's current unmetered rate. The OCA's witness, Mr. Watkins, identified nine wastewater rate zones that have both metered and unmetered residential rates. He explained that for some zones, the metered and unmetered rates are relatively close; but in others, there is a significant difference between rates for an average metered rate customer and flat rate customer. OCA St. 4 at 20; OCA Sch. GAW-8. For example, compared to metered rates, flat rates are 57% higher in Zone 5 and 30% lower in the

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[89] The OCA accepted Aqua's proposed customer charge increase for Zone 9 residential customers. *See* OCA M.B. at 241.

Limerick Zone.[90] In this regard, the OCA requested that the Company study the reasonableness of its unmetered rates and provide the results in its next base rate proceeding. OCA St. 4 at 21.

According to Aqua, there are valid reasons for the differences between metered and unmetered rates. Aqua further explained that its unmetered rates assume an average usage of 4,000 gallons per month, which is standard industry practice. Aqua St. 5-R at 14-15. As to customers who pay a flat rate in Lake Harmony and Tobyhanna, Aqua took the position that customers pay to have wastewater service available, whether they are present at the service address for a few days or for longer periods of time; residency status is not a determinative factor. Aqua St. 9-R at 29.

Based on the concerns and testimony of several Lake Harmony wastewater customers regarding flat wastewater rates, as voiced at the public input hearings, the OCA's witness, Mr. Watkins, submitted supplemental direct testimony addressing the issue in Lake Harmony and several other developments where Aqua provides wastewater service, in which the water service is unmetered. OCA St. 4 SUPP. At those locations, wastewater customers either have their own wells or receive unmetered water from a community system. In these situations, the Company will bill wastewater service at a flat rate, where it uses average metered wastewater usage from customers with metered rates to develop a proxy of usage, which is then used to develop the rates. The OCA recommended that Aqua develop a pilot program to install meters for those customers who want them.[91] Under this proposal, Aqua would install water meters on customer-owned wells on an opt-in basis. These opt-in customers would be billed at the applicable

[90] The current average monthly metered rate for the Avon Grove Division in Rate Zone 5 is $113 (before DSIC) compared to $177 for flat-rate customers. The current average monthly metered rate for Rate Zone 7 – Limerick is $40 (before DSIC) compared to $28 for flat rate. OCA St. 4 at 20, Table 8.

[91] Complainant John Day wrote in support of the OCA's proposal. Letter in Lieu of Brief filed January 10, 2022.

metered rate. Mr. Watkins further proposed that the Company install water meters on other customer-owned wells based upon a random sample of 10% to 20% of the unmetered customers. These customers would be billed on a flat-rate basis, but the Company would prepare "shadow" bills based upon consumption. OCA St. 4 SUPP. at 2.

Aqua opposed this recommendation for a variety of reasons including cost and feasibility. Aqua St. 5-R at 17-18; Aqua St. 9-R at 29-30.

The OCA's witness, Mr. Watkins, further testified in response to the result of the Company's analysis of capping non-seasonal wastewater rates. *See* OCA St. 4 at 21-22. As previously indicated, Aqua performed an analysis of the feasibility of implementing a summer wastewater cap, as required by the settlement of its 2018 base rate proceeding. *See* Aqua Exh. 5-C. The basis for the cap is to address potential inaccuracies in the calculation of wastewater volumetric charges during the summer months when irrigation, swimming pool filling, and other outside watering activities are traditionally in use.[92] Mr. Watkins recommended that the Company continue to study the feasibility of: (1) a capping mechanism with a winter multiplier greater than 100%;[93] and (2) the implementation of irrigation water meters on a customer-by-customer request basis. OCA St. 4 at 22.

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[92] Mr. Watkins testified that "In my experience, I am familiar with two mechanisms to fairly treat those customers whose Summer irrigation use is significant. The first and most prevalent are capping mechanisms similar to the one considered in the study conducted by Aqua. However, more often than not, I have seen capping mechanisms with an admittedly arbitrary multiplier such as 125% of Winter usage or 150% of Winter usage as a cap. This is different from the Company's study wherein they used a multiplier of 100%; *i.e.*, simply capped at average Winter usage." OCA St. 4 at 22.

[93] The OCA acknowledged that Aqua has already conducted an analysis of a capping mechanism with a multiplier of 100% but recommended that Aqua could study a multiplier greater than 100%. OCA St. 4 at 21-22.

Aqua opposed further study of a cap on non-seasonal wastewater rates, noting that it complied with its prior commitment from the 2018 base rate proceeding to provide a study as a part of this proceeding, and the results of the study revealed that a cap only benefits high water users. In addition, the imposition of a cap on non-seasonal wastewater rates could also result in a need to shift more wastewater revenue requirement to water rates. Aqua explained that the further studies proposed by the OCA will produce results similar to the analysis presented by Aqua in this case, and thus further studies are not necessary. Aqua St. 5-R at 15. Aqua also disagreed with the OCA's proposal to install irrigation meters on a customer opt-in basis, noting that such an implementation would increase revenue requirement for the installation and reading of meters and would not reduce revenue requirement recovery. Aqua R.B. at 104.

2. Recommended Decision

In her Recommended Decision, the ALJ recommended that the Commission adopt the overall wastewater rate design advocated by I&E, which was proposed to obtain I&E's Act 11 revenue allocation proposal:

> I recommend that the Commission accept the methodology of I&E for allocating revenue and designing wastewater rates. I&E's approach takes into consideration the number of water and wastewater customers in each system and balances the goal of moving rates toward alignment with the cost of service, while also mitigating some of the large rate increases that would result if no allocation of wastewater revenue was approved. I&E's approach acknowledges the benefits received by the communities serviced by the Acquired Systems from the sale of their systems to Aqua, but is less complicated than the method advocated by OCA.

R.D. at 91.

Although the ALJ recommended adoption of I&E's proposed wastewater rate design, including its recommended customer charges, the ALJ found Aqua's water and wastewater residential customer cost analyses upon which it based its proposed increases to customer charges to be reasonable, stating:

> While the Commission generally disfavors the inclusion of indirect costs into the calculation of customer charges, the Commission has nevertheless permitted the allocated portions of certain indirect costs such as employee benefits, local taxes and other general and administrative costs. I find that Aqua's witness adequately demonstrated that the indirect costs included in her study fall within the ambit of permissible general and administrative costs.

R.D. at 95.

In this regard, the ALJ implicitly rejected the OCA's residential customer charge proposals for water customers, while nonetheless, adopting I&E's recommended water rate design changes, based upon its proposal to reduce the Act 11 subsidy from water customers.[94] R.D. at 91, 95.

Regarding the reasonableness of unmetered rates, the ALJ agreed with the OCA and recommended that Aqua study whether a different method of calculating a flat rate would be more reasonable for some systems than applying a system-wide average and report the results in its next base rate case. R.D. at 98.

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[94] I&E asserted that the Company's proposed percentage increases to the water customer classes should all be scaled back to 20% of the Company's original proposed percentage increases. I&E M.B. at 73. I&E explained that this scale back of water rates, including customer charges, should be proportional to the percentage increase originally proposed by the Company. I&E St. 4 at 18-20.

Although the ALJ saw the benefits of Aqua studying the reasonableness of its unmetered rates, finding that there may be areas in Aqua's service territory where unique circumstances may suggest that a different method of calculating a flat rate is more reasonable, ALJ Long however, rejected the OCA's proposal for the implementation of a metering pilot for flat-rate customers in the Lake Harmony service area, providing the following reasoning:

> OCA does not include any cost estimates for its recommended pilot program but proposes that the meters be installed at Aqua's cost. No doubt, that cost would be socialized to all of Aqua's wastewater ratepayers. Some customers would "opt-in" for the installation of a meter. Other customers would not opt-in. This adds a layer of administrative complexity and costs, including costs to test and maintain meters and administer this program. While the Commission certainly favors consumption-based utility rates, it is not clear that the cost of OCA's proposed pilot will achieve overall benefits to Aqua's customers that will outweigh the costs. Therefore, I recommend the Commission reject OCA's proposal.

R.D. at 97.

Finally, the ALJ recommended that the Commission reject the OCA's recommendation regarding additional studies of a non-seasonal wastewater capping mechanism. The ALJ agreed with Aqua that further study of a non-seasonal wastewater capping mechanism is unnecessary, reasoning that the OCA did not demonstrate that further study would yield better results. R.D. at 99.

3. Exceptions and Replies

a. Aqua Exception No. 10 and Replies

In its Exception No. 10, Aqua submits that the ALJ erred in recommending that Aqua be required to provide a study in its next base rate case that would determine the reasonableness of unmetered rates. Aqua maintains its position, as argued by its witness, Ms. Heppenstall, that such a study is not needed. Aqua Exc. at 35. Aqua contends that Ms. Heppenstall fully explained the basis for the differences between metered and unmetered rates, as follows:

> The large difference in Limerick and East Norriton is based on the fact that these are new acquisitions with legacy rates. The Company will rectify this disparity when it sets the rates in this case. For the other rate zones, the unmetered rate is based on an assumed average usage of 4,000 gallons per month plus a customer charge. The average usage of <u>4,000 gallons is substantiated in the Company's prior rate case as the pre-COVID pandemic average residential usage was 4,068 per month for the residential class.</u> For example, in Bridlewood, the calculation of the unmetered rate under present rates equals $31.00 plus the usage rate of .7600 per 100 gallons at 4000 gallons ($31.00 + .7600 X 40) or $61.40. <u>This calculation of the unmetered rate based on average usage is standard in the industry and used by other regulated water and wastewater utilities in Pennsylvania.</u> For example, Pennsylvania American Water Company's unmetered wastewater rate for Zone 1 for 2022 is $78.41 per month which was designed to equal the metered customer charge plus the usage rate multiplied by an average usage of 3,458 gallons.

Aqua M.B. at 244 (citing Aqua St. 5-R at 14-15) (emphasis added by Aqua).

Aqua further argues that the ALJ did not find the Company's use of unmetered rates or use of an average monthly usage of 4,000 gallons to be unreasonable, but rather only found "that the use of a 4,000-gallon average monthly usage rate may not result in fair rates, and that there may be areas where a different method of calculating a flat rate is more reasonable." Aqua Exc. at 35 (citing R.D. at 98 (emphasis added by Aqua)). Aqua notes that its witness, Mr. Todd M. Duerr, credibly testified that the average usage of 4,000 gallons was substantiated by the pre-COVID pandemic average residential usage shown in Aqua's last base rate proceeding, and that its average usage amount was consistent with the average usage of other water utilities such as Pennsylvania-American Water Company. Aqua Exc. at 35 (citing Aqua St. 9-R at 14-15).

Additionally, Aqua posits that any results of such a study would be "speculative," since many of the areas without metered water service have individual customer wells, which prevents access to the usage data needed to assess average usage for an area. Aqua Exc. at 35.

In its Replies, the OCA asserts that Aqua misunderstood the ALJ's reasoning based on her concern that the usage amount assumption (derived from the system-wide average) for flat rates may not be reasonable for all areas of Aqua's service territory, particularly in areas where there is a significant mix of types of housing or other unique circumstances. OCA R. Exc. at 15 (citing R.D. at 98; Aqua Exc. at 35). Therefore, the OCA maintains that, where the Company's use of a system-wide average in the derivation of its unmetered rates is causing an unreasonable disparity in the rates charged to metered and unmetered customers, it is reasonable for Aqua to study and propose adjustments to its unmetered rates, which may include an adjustment to the usage assumption applied in a particular territory. OCA R. Exc. at 15.

Moreover, in reply to Aqua's argument that due to customers being served by unmetered individual wells in some areas of its service territory, it lacks access to the usage data needed to perform such an analysis, the OCA notes that Aqua is ignoring the nine individual territories where it charges some customers metered rates. OCA R. Exc. at 15. The OCA continues that Aqua has usage data at the individual system level, which informs its operations and compliance with regulatory requirements for wastewater collection, conveyance, treatment, and discharge. OCA R. Exc. at 15 (citing 25 Pa. Code. Chapters 91, 92a). Other information regarding housing size, occupancy and seasonal usage may be available from property owners' associations, local municipalities, and observation. OCA R. Exc. at 15.

b. OCA Exception No. 12 and Replies

In its Exception No. 12, the OCA disagrees with the ALJ's adoption of what it believes are overly inclusive residential customer cost analyses performed by Aqua, upon which the Company has based its residential customer charges for water and wastewater customers. OCA Exc. at 19-22.

The OCA maintains that a review of the specific indirect costs included in Aqua's studies show they do not fall within the ambit of costs that the Commission has historically permitted but are merely costs related to Aqua's general operation as a utility. The OCA noted its reliance on Commission precedent, which has generally permitted only expenses directly related to meter reading, customer service, accounting and customer records and collection, but has allowed costs associated with direct labor costs, including employee benefits, workers compensation insurance and payroll taxes, where portions of indirect costs have been permitted on a case-by-case basis. OCA Exc. at 20 (citing *Pa. PUC v. Metropolitan Edison Company*, 60 Pa. P.U.C. 349 (1985); *Pa. PUC v. West Penn Power Company*, 59 Pa. P.U.C. 552 (1985); *Pa. PUC v. West Penn Power Company*, 1994 Pa. PUC LEXIS 144, *154; *Pa. PUC v. National Fuel Gas Distribution Corporation*, 83 Pa. P.U.C. 262, 371 (1994); *see also*, *2004 PPL Order* and *Aqua 2004 Order*). The OCA notes that more recently, the Commission has rejected a utility's proposed customer charge increase based on a cost analysis that included indirect costs.

OCA Exc. at 20 (citing *Pa. PUC v. PPL Gas Utilities Corporation*, Docket No. R-00061398 (Order entered February 8, 2007) at 137) (*2007 PPL Gas Order*).

The OCA submits that even when the additional types of costs that the Commission allowed in the *PSWC 2004 Order*[95] are included, the indicated customer costs are below the current Main Division 5/8" residential water customer charge of $18.00 and, thus, there is no reasonable basis to increase the customer charges. OCA Exc. at 21. The OCA also maintains that Aqua's proposal to increase the wastewater Zone 1 5/8" residential customer charge to $39.10 should be rejected because the study that Aqua relies on improperly includes indirect overhead costs that are not reasonably related to connecting and maintaining a customer's account, such as uncollectibles expense and rate case amortization. OCA Exc. at 21.

In addition to not supporting that level of customer charge increases with a direct cost study, the OCA contends that the magnitude of the increases is not supported by the public policy of gradualism and incentivizing conservation. OCA Exc. at 21 (citing *2007 PPL Gas Order*; *Pa. PUC v. Community Utilities of Pennsylvania, Inc.*, R-2021-3025206, *et al.* (Order entered January 13, 2022) at 62-63). The more revenue recovered through customer charges, the lower the volumetric rate, which impacts customers' incentive to conserve. OCA Exc. at 21.

Contrary to the OCA's claims in its Exceptions, Aqua maintains that the items the OCA asserts are "overhead costs" or "indirect expenses" are actually necessary for the support of customer facilities and customer accounting and should be considered direct costs. Aqua R. Exc. at 11 (citing Aqua M.B. at 234-35).

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[95] *Pa. PUC v. Philadelphia Suburban Water Company*, Docket No. R-00038805 (Order entered August 3, 2004) at 72 (*PSWC 2004 Order*).

Moreover, Aqua counters that its customer cost analysis is consistent with Commission precedent; the ALJ evaluated these costs "on a case-by-case basis" consistent with this precedent. Aqua R. Exc. at 11 (citing Aqua M.B. at 235; R.D. at 95). Aqua further asserts that the OCA's argument that Aqua's proposed customer charges violate gradualism and do not incentivize conservation should be rejected. Aqua R. Exc. at 11 (citing OCA Exc. at 21). Aqua argues that its rates were designed to balance these considerations with the cost of serving its customers and demonstrated that its rate design guidelines were reasonable and appropriate. Aqua R. Exc. at 11-12 (citing Aqua M.B. at 230-33, 237-38).

c. OCA Exception No. 13 and Replies

In its Exception No. 13, the OCA disagrees with the ALJ's adoption of I&E's wastewater rate design methodology. OCA Exc. at 22 (citing R.D. at 88-89, 91, 96; OCA M.B. at 101-04; OCA R.B. at 60-61). Rather, the OCA maintains that its proposed wastewater rate design for the legacy systems and acquired systems is more reasonable and should be adopted. OCA Exc. at 22.

The OCA noted that I&E witness, Mr. Kubas, acknowledged that he normally would not support increasing the customer charges above cost, but he did so in this case because it provided more revenue. OCA Exc. at 22 (citing I&E St. 5 at 10, 38; I&E St. 5-R at 5). The OCA argues the additional revenue is derived from I&E's proposed 46.8% increase to Zone 1 customer charges, from $31.00 to $45.50 per month, which is nearly two times the increase proposed by the Company as well as I&E's proposed increases to all of the 5/8 customer charges that range between 26% and 66% and exceed their costs. OCA Exc. at 22 (citing I&E Exh. 5, Schs. 2-8).

On the other hand, the OCA submits that under its proposal, customer charges are supported by cost analyses and move customer charges toward consolidation with the main wastewater zone customer charges. The OCA posits that under its proposal, customers will: (1) be charged cost-based fixed rates; (2) receive proper price signals; and (3) have more control of their bills. OCA Exc. at 22-23 (citing OCA R.B. at 58-61; OCA M.B. at 102-04; OCA St. 4 at 17-20). Further, the OCA contends that unlike I&E's proposal, the OCA's recommendations flow from its proposed customer charges for Zone 1 and reasonably move other divisions toward consolidation with those charges. OCA Exc. at 22 (citing OCA St. 4 at 17-20).

In its Replies, Aqua submits that the OCA's argument regarding the adoption of I&E's proposed wastewater rate design should be denied for the same reasons that the Company opposes the ALJ's adoption of I&E's proposed wastewater rate design and revenue allocation. Aqua R. Exc. at 12 (citing OCA Exc. at 22-23; Aqua Exc. at 31-34; Aqua R.B. at 102-04; Aqua M.B. at 237-43).

In its Replies, I&E notes that it made revisions in its final schedule that addressed the positions proffered by other Parties, including the OCA. Therefore, I&E asserts that the Commission adopt I&E's final wastewater revenue allocation and rate design, as discussed in I&E Exception No. 2. I&E R. Exc. at 17 (citing I&E Exc. at 4-5; I&E St. 5-SR at 4; I&E Exh. 5-SR, Sch. 1 at 1).

d. OCA Exception No. 14, Mr. Osinski's Exceptions, and Replies

In its Exception No. 14, the OCA submits that the ALJ erred by rejecting its proposal for the implementation of a metering pilot for flat-rate customers in the Lake Harmony service area. OCA Exc. at 23-25.

Referencing Aqua's continuation of deduct metering[96] programs for some of its acquired systems, specifically its Cheltenham service territory, the OCA contends that the cost and operational data from that existing deduct metering program can help to inform how the pilot is structured. Moreover, the OCA argues that the benefits of a pilot program, which assists in moving flat-rate customers to metered rates in an area where a significant number of customers may use less than (or more than) the average usage of 4,000 gallons, outweigh the costs, which, according to the OCA, should be reasonable since the pilot would involve only a few hundred customers. OCA Exc. at 23-24.

As such, the OCA excepts to the ALJ's suggestion to delay a remedy until the next base rate case because it will delay relief to customers who, under the OCA's proposal, could begin participating in a pilot program within a few months of a final order in the current case. The OCA maintains that Aqua should be directed to adopt a program, on a pilot basis, as a reasonable and measured response to the concerns raised by its customers regarding flat rates. OCA Exc. at 24-25.

In its Replies, Aqua maintains its opposition to any requirement to install Company water meters on customer owned (wells) or community owned water supplies, in order to implement metered wastewater rates, reemphasizing the arguments presented in its briefs. Aqua R. Exc. at 12-13 (citing Aqua M.B. at 243-44; Aqua R.B. at 103). Aqua adds that it has no right to enter customers' premises to demand the installation of water meters where Aqua does not provide the water supply and posits that an "opt-in" pilot will only lead to meter installations where customers have decided that their usage is below average, thereby negating the validity of the "pilot." Aqua R. Exc. at 12.

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[96] Deduct metering is a mechanism which allows individual customers, using a significant amount of outside water, such as for an irrigation system, to have a separate irrigation water meter installed. This second meter, known as a deduct meter, measures the flow of water that does not enter the wastewater system and is used to calculate a reduction in wastewater charges. *See generally*, OCA St. 4 at 21-22, and 25; OCA Exc. at 25; Aqua R. Exc. at 13; and OCA M.B. at 109.

Mr. Osinski also filed exceptions to the Recommended Decision, specifically taking issue with the flat-rate service provided to the Camp Stead Property Owners Association, which is part of Aqua's Tobyhanna Township Division. Mr. Osinski argues that the private development (Camp Stead Property Owners Association) in which he resides is served by a metered community well; however, Aqua does not meter his wastewater. Mr. Osinski contends that Aqua's practice of basing his flat rate on 4,000 gallons of consumption per month is unjustified, and as a result, he is being charged far more than he uses. Osinski Exc. at 1-4.

In its Replies to the Exceptions of Mr. Osinski, Aqua points to its response to OCA Exception No. 14, in which it addresses concerns related to the flat-rate service provided to certain customers. Additionally, Aqua notes that it responded to concerns raised by customers at residences on Camp Stead Circle in its Main Brief. Aqua R. Exc. at 13 (citing Aqua M.B. at 179-180).

Furthermore, Aqua notes that Exhibits A-G, L and Q, attached to Mr. Osinski's Exceptions, appear to be extra record evidence, not permitted to be introduced in his Exceptions, and thus, should be disregarded. Aqua R. Exc. at 13 (citing *Application of Apollo Gas Company*, 1994 Pa. PUC LEXIS 45 (Order entered February 10, 1994) at *8-9 (denying party's attempt to introduce extra-record evidence in its exceptions)).

e. OCA Exception No. 15 and Replies

In its Exception No. 15, the OCA submits that the ALJ erred by not requiring the Company to study the feasibility of affording additional customers the option of deduct metering. OCA Exc. at 25-26 (citing R.D. at 99).

The OCA explains that the ALJ did not distinguish between the studies recommended by its witness, Mr. Watkins, and, as such, did not address the OCA's recommendation for an alternative study, which Mr. Watkins opined may be the fairest for Aqua – installing irrigation water meters on a customer-by-customer request basis. OCA Exc. at 25 (citing OCA M.B. at 109-10; OCA R.B. at 65-66; OCA St. 4 at 22). The OCA notes that, to its knowledge, Aqua has not already conducted any studies on irrigation metering, also referred to as deduct metering. *Id*.

Further, the OCA argues that Aqua's objection to studying the feasibility of opening its deduct metering program to Aqua's non-Cheltenham customers is not reasonable, since the Company already has a deduct metering program in its Cheltenham service territory and two years of cost and operational data from that program. Therefore, the OCA submits that the results of that study, including either a proposal to make deduct metering available to more or all customers or a detailed explanation for why Aqua believes expansion is infeasible in other service territories, should be filed no later than Aqua's next base rate case. OCA Exc. at 25-26.

Contrary to the OCA's arguments, Aqua replies that no such study should be ordered. Aqua maintains its argument that the installation of a second meter to measure usage deductions will only increase the revenue requirement for installing and reading meters and will not reduce the revenue requirement that needs to be recovered. Aqua R. Exc. at 13 (citing Aqua R.B. at 104; Aqua M.B. at 244-45).

4. Disposition

a. Water and Wastewater Rate Design

As previously explained, the allocation of the rate increase among the customer classes of both Aqua's water and wastewater divisions, and ultimately the rate design under each division, was a significant issue in this proceeding.[97] In cases such as the instant one before us, the ALJ and the Commission are faced with the difficult task of balancing the justness and reasonableness of all components of revenue allocation and rate design. The reality is, as a result of the difficult choices that must be made, all customer classes will inevitably experience some degree of an undesired impact. Consistent with our discussion, *supra*, regarding the issue of revenue allocation, and based on our review of the supporting information contained in the record, we find that the ALJ's determinations regarding rate design are sufficiently supported by the evidentiary record. Accordingly, based on our discussion below, we find that the OCA's arguments against the ALJ's recommendation concerning this matter are without merit.

In reaching this determination, we have reviewed the rate designs adopted by the ALJ and found them to be reasonable, affording appropriate primary consideration to cost causation principles per *Lloyd* in tandem with secondary consideration for the value of service, gradualism, and affordability.

There is not a prescribed "ratemaking formula" that the Commission must adhere to when determining just and reasonable rates. Rather, the Commission "has broad discretion in determining whether rates are reasonable" and "is vested with discretion to decide what factors it will consider in setting or evaluating a utility's rates." *Popowsky II*. Included in the Commission's broad ratemaking authority is the authority to approve alternative rates and rate mechanisms, including formula rates as well as decoupling mechanisms, performance-based rates, and multiyear rate plans. 66 Pa. C.S. § 1330(b)(1)(i)-(v).

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[97] In this proceeding, the Company invoked the Commission's authority under Section 1311(c) of the Code to mitigate the impact of revenue increases on wastewater customers by recovering a portion of the Company's wastewater revenue requirement from its total water and wastewater customer base. *See* 66 C.S. § 1311(c).

With that said, we acknowledge that a set of ratemaking norms have been developed over time and have been consistently utilized by parties in rate cases before the Commission to determine the appropriate level of a utility's requested revenue increase in accordance with all applicable legal and constitutional standards. These norms, or traditional ratemaking methodologies,[98] are used to determine a utility's cost of providing service, or its revenue requirement, and to determine appropriate rate structure, which includes, among other things, the appropriate allocation of the revenue requirement to various customer classes. However, while these ratemaking norms provide a rational and methodical way to analyze and determine the utility's cost of service, they also permit the consideration and weighing of important factors or principles in setting just and reasonable rates, such as quality of service,[99] gradualism,[100] and rate affordability.[101]

We acknowledge that there are several factors that must be considered when designing a rate recovery proposal, including the concepts of gradualism and affordability. We emphasize, however, that while affordability is permitted to be considered, it is but one of many factors to be considered and weighed by the Commission in determining the utility's rates. The rate increase reflects the business challenges the Company currently faces, including required investments in the repair/replacement or improvement of its distribution systems, including newly acquired

[98] *See, e.g., Pa. PUC, et al. v. PPL Electric Utilities Corporation*, Docket Nos. R-2015-2469275 *et al*. (Recommended Decision issued October 5, 2015) at 32-33.

[99] *See* 66 Pa. C.S. §§ 523, 526(a).

[100] *See Lloyd*, 904 A.2d at 1020 (explaining that gradualism is the principle under which utility rates are gradually increased in order to avoid rate shock, as part of what is overall considered a reasonable rate under the circumstances and is permitted in implementing large rate increases).

[101] *See Pa. PUC et. al v. Twin Lakes Utilities, Inc*., Docket No. R-2019-3010958 (Order entered March 26, 2020) at 48, 80 (the ALJ did not err in considering evidence relating to the various quality of service and rate affordability issues in the proceeding and factoring in such evidence as part of her overall determination on which expert witnesses' cost of equity to adopt for setting just and reasonable rates).

water and wastewater distribution systems; and the high costs associated with maintaining a distribution system necessary to provide safe and reliable water and wastewater service within the Commonwealth.

As discussed, *supra*, Aqua's proposal, establishing an Act 11 subsidy close to one-third of the wastewater revenue requirement would result in wastewater rates that do not bear a reasonable relationship to the Company's cost of serving those customers. In consideration of Aqua's recent Section 1329 acquisitions and the consequences of the Company's request to have water customers subsidize rate increases for customers in wastewater Rate Zones 1 through 6, as well as to absorb a significant portion of the revenue shortfalls of the newly acquired wastewater systems, Rate Zones 7 through 11, we find I&E's approach in limiting the Act 11 subsidies[102] and its subsequent rate design proposals, adopted by the ALJ, to be a reasonable compromise between the conflicting objectives of moving towards consolidated rates and maintaining gradualism in customer bill impacts.

Table 15, below, provides a comparison of residential wastewater bills for a typical residential customer under the Company's proposed rates and under I&E's proposal. Under Aqua's proposed rates, residential wastewater customers would see increases ranging from 7.9% to 84.9%, with Rate Zone 5 – Newlin Green experiencing a proposed decrease. Under I&E's proposed rates, residential wastewater customers would see increases ranging from 20.3% to 86.0%, excluding the increase to Rate Zone 10 – Whitpain, where the average residential customer will experience an increase of approximately 106.6%. As I&E noted, this larger than average increase is

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[102] I&E's approach for allocating wastewater revenue and designing wastewater rates allows for each type of utility service to recover as much of the cost of providing services as possible without removing the Act 11 subsidy, which would result in unreasonably large increases to the monthly customer charges, usage rates, unmetered rates, and average bills for both residential and commercial wastewater customers.

justified for three reasons: (1) the average bill under current rates of $31.66 per month is the lowest average bill for all zones; therefore, to move the average bill closer to other average bills, a larger percentage increase is necessary; (2) the Company's desire to consolidate all Zone 10 rates justifies the higher rates for Zone 10 – Whitpain to match Zone 10 – East Norriton rates; and (3) even with higher rates causing a higher than average increase for Zone 10 – Whitpain, total Rate Zone 10 operations will continue to need $1,378,735 of subsidy from water customers. *See* I&E St. 5 at 52-53.

Wastewater Division
Bill Comparison of 5/8" Metered Residential Customers with Average Usage*

	Average Current Monthly Bill	Aqua Proposal		I&E Proposal	
		Monthly Bill	% Increase	Monthly Bill	% Increase
RZ 1 - Main	$64.47	$77.49	**20.2%**	$90.12	**39.8%**
RZ 1A	$59.01	$77.49	**31.3%**	$90.12	**52.7%**
RZ 1B	$64.05	$77.49	**21.0%**	$90.12	**40.7%**
RZ 2 - Main	$71.82	$77.49	**7.9%**	$100.32	**39.7%**
RZ 3 - Main	$84.00	$101.03	**20.3%**	$109.04	**29.8%**
RZ 4 - Main	$105.00	$125.00	**19.0%**	$131.13	**24.9%**
RZ 5 - Main	$118.02	$141.94	**20.3%**	$141.94	**20.3%**
RZ 5 - Newlin Green	$147.00	$141.94	**-3.4%**	$141.94	**-3.4%**
RZ 6 - Masthope	$45.82	$55.15	**20.4%**	$66.60	**45.4%**
Zones Recently Acquired					
RZ 7 - Limerick	$39.73	$72.94	**83.6%**	$73.90	**86.0%**
RZ 8 - East Bradford (Mulit-Family Residential)	$55.36	$83.42	**50.7%**	$99.80	**80.3%**
RZ 9 - Cheltenham	$36.53	$49.34	**35.1%**	$57.20	**56.6%**
RZ 10 - East Norriton	$38.52	$58.53	**51.9%**	$65.40	**69.8%**
RZ 10 - Whitpain	$31.66	$58.53	**84.9%**	$65.40	**106.6%**
RZ 11 - New Garden	$73.03	$100.34	**37.4%**	$130.99	**79.4%**

* Average 5/8" residential customer using 4,000 gallons per month.

Table 15: Comparison of residential wastewater bills for a typical residential customer under the Company's proposed rates and under I&E's proposal. *See* Aqua Exh. 5-B, Part II, Sch. WW-7; *see also*, I&E Exh. 5, Sch. 2 at 2-4, Sch. 3 at 2, Sch. 4 at 2 and 4, Sch. 5 at 2, Sch. 6 at 2 and 4, Sch. 7 at 2-3; I&E Exh. 5-R, Sch. 2 at 2.

Furthermore, since the average bill under current rates is lower in Rate Zones 1 and 6 than it is for Rate Zones 2 through 5, it is reasonable that Rate Zones 1 and 6 would experience larger percentage increases compared to Rate Zones 2 through 5. Since the Company presented one cost of service study for Rate Zones 1 through 6, there is no justification for such a wide variety in rates and corresponding average bills.

The overall bill impact to a typical residential water customer bill would be overall less than the Company's proposal,[103] since I&E's recommended water rate design changes are based upon its proposal to reduce the Act 11 subsidy from water customers. In this regard, a bill for a typical residential water customer would reflect I&E's recommendation that the Company's water rates be scaled back to 20% of the Company's original proposed percentage increases, and that the recommended scale back, including customer charges, be proportional to the percentage increase originally proposed by the Company. *See* I&E M.B. at 73; I&E St. 4 at 18-20.

Moreover, the higher percentage increases to a typical residential customer bill recommended by I&E's rate design for Rate Zones 7 through 11 are indicative of the substantial revenue shortfall attributable to these newly acquired systems, even under the Company's proposed rates. Without the, albeit, more moderate Act 11 subsidy proposed by I&E, compared to Aqua's proposal, these wastewater rates would necessarily have to be increased even further. As such, we find I&E's rate design reasonably mitigates the impact of revenue increases onto these wastewater customers by recovering a portion of the Company's wastewater revenue requirement from its total water and wastewater customer base.

The OCA also excepts to the ALJ's recommendation, arguing that Aqua's proposed customer charges are based on its flawed cost of service study results, violate the principle of gradualism, and would result in a disincentive for customers to engage in conservation activities. Therefore, the OCA's wastewater rate design recommendations include its contention that there is no cost justification for increasing the present $31.00

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[103] Under the Company's proposal, a residential customer in the Main Division of Rate Zone 1, using 4,000 gallons of water per month, would experience a monthly bill increase from $69.35 to $81.32, or 17.3% per month, and residential customers in other water divisions would experience increases ranging from 17.3% to 51.3%. *See* Aqua Exh. 5-A, Part II, Sch. 8.

per month 5/8" residential customer charge in Rate Zone 1. Upon our consideration of the evidence and record herein, we conclude that the ALJ correctly recommended that, consistent with the *Aqua 2004 Order*, and subsequently affirmed in the *2012 PPL Order*, other customer-related costs are properly includable in a customer cost analysis. We find that the OCA proposed limitation of costs excludes customer costs that should be included in a customer charge and is unreasonably narrow.

As previously indicated, although the ALJ accepted Aqua's water and wastewater residential customer cost analyses upon which it based its proposed increases to customer charges, the ALJ adopted I&E's proposed rate design which includes the wastewater customer charges summarized in Table 16, below.

Further, we are persuaded by I&E's reasoning for its increase to the 5/8" residential customer charge for Rate Zone 1:

> While I normally would support not increasing the monthly 5/8th inch residential customer charge based upon cost, there are other factors to consider in this case. First, the present \$31.00 per month customer charge is below the monthly customer charges in Zones 3 through 5. Therefore, in order to move towards consolidation of the customer charges in these zones, the present Zone 1 customer charge of \$31.00 per month should be increased. Customer charges should be consolidated in Zones 1 through 6 for fairness and simplicity. Second, the remaining revenue increase will have to come from increasing the usage charge. Therefore, given this low customer charge, I recommend that the OCA proposal be rejected.

I&E St. 5-R at 5-6. Additionally, as I&E indicated, the OCA did not address the remaining meter sizes in Rate Zone 1, the other classes in Rate Zone 1, or the other customer charges in Rate Zones 2 through 6.

Wastewater Division
Comparison of 5/8" Metered Residential Customer Charges

	Current	**Aqua Proposal**		**I&E Proposal**	
	Customer Charge	Customer Charge	% Increase	Customer Charge	% Increase
RZ 1 - Main	$31.00	$39.10	**26.1%**	$45.50	**46.8%**
RZ 1A	$31.00	$39.10	**26.1%**	$45.50	**46.8%**
RZ 1B	$31.00	$39.10	**26.1%**	$45.50	**46.8%**
RZ 2 - Main	$36.00	$39.10	**8.6%**	$52.80	**46.7%**
RZ 3 - Main	$46.00	$58.09	**26.3%**	$62.70	**36.3%**
RZ 4 - Main	$62.00	$77.50	**25.0%**	$81.30	**31.1%**
RZ 5 - Main	$74.00	$93.45	**26.3%**	$93.45	**26.3%**
RZ 5 - Newlin Green	$110.00	$93.45	**-15.0%**	$93.45	**-15.0%**
RZ 6 - Masthope	$39.64	$50.10	**20.4%**	$56.20	**41.8%**
Zones Recently Acquired					
RZ 7 - Limerick	$28.10	$39.48	**40.5%**	$39.50	**40.6%**
RZ 8 - East Bradford (Mulit-Family Residential)	Current Flat Rate	$39.10		$55.00	
RZ 9 - Cheltenham	$20.89	$28.21	**35.0%**	$30.00	**43.6%**
RZ 10 - East Norriton	$21.08	$32.37	**53.6%**	$35.00	**66.0%**
RZ 10 - Whitpain	$31.66	$32.37	**2.2%**	$35.00	**10.5%**
RZ 11 - New Garden	$37.64	$51.71	**37.4%**	$43.00	**14.2%**

Table 16: Comparison of 5/8" metered residential wastewater customer charges. *See* I&E Exh. 5, Schs. 2-7 at 1; I&E Exh. 5-R, Sch. 2 at 1.

With regard to the concerns expressed by the OCA that the Company's proposed customer charges will discourage conservation, we note that the customer charges, shown above, in the context of the total monthly bill for a typical 5/8" meter residential wastewater customer, would comprise approximately 47% to 91% of the charges on the bill under the Company's proposal and only approximately 33% [($43.00 ÷ $130.99) x 100=33%] to 84% [($56.20 ÷ $66.60) x 100 = 84%] under I&E's wastewater rate design proposal. This is less than the portion of a typical bill for a 5/8" meter wastewater residential customer under current rates, of which approximately 48% to 87% is attributable to the customer charge, as shown in Table 17 below:

Wastewater Division
Comparison of the Portion of a Customer's Bill Attribuable to the Customer Charge

	Current Rates	Aqua Proposed Rates	I&E Proposed Rates
RZ 1 - Main	48%	50%	50%
RZ 1A	53%	50%	50%
RZ 1B	48%	50%	50%
RZ 2 - Main	50%	50%	53%
RZ 3 - Main	55%	57%	58%
RZ 4 - Main	59%	62%	62%
RZ 5 - Main	63%	66%	66%
RZ 5 - Newlin Green	75%	66%	66%
RZ 6 - Masthope	87%	91%	84%
Zones Recently Acquired			
RZ 7 - Limerick	71%	54%	53%
RZ 8 - East Bradford (Mulit-Family Residential)	100%*	47%	55%
RZ 9 - Cheltenham	57%	57%	52%
RZ 10 - East Norriton	55%	55%	54%
RZ 10 - Whitpain	100%*	55%	54%
RZ 11 - New Garden	52%	52%	33%

*Average use customers, using 4,000 gallons per month, are currently billed a flat rate.

Table 17: Comparison of the portion of a customer's wastewater bill attributable to the customer charge.

Regarding the Company's water rate design proposal, the portion of charges attributable to the customer charge on a typical 5/8" meter water residential customer would range from approximately 21.6% [($4.90 ÷ $22.66) x 100 = 21.6%] for customers in the Phoenixville Division to 39.8% [($32.40 ÷ $81.32) x = 39.8%] for customers in Rate Zone 3 – Main. Reflective of I&E's effort to reduce the Act 11 subsidy, with which we agree, I&E's proposal simply scales back the Company's proposed percentage increases for water customers to 20% of the Company's original proposal. Therefore, we find that I&E's proposal reasonably balances the principles of gradualism with the challenges of rate consolidation, especially those that come with newly acquired systems, while preserving adequate opportunity for customer savings due to conservation efforts. As such, we find no basis to reverse the ALJ's recommendation. Accordingly, OCA Exception Nos. 12 and 13 are denied.

b. Unmetered Residential Wastewater Rates

Aqua explained that similar to many wastewater systems throughout the Commonwealth, Aqua does serve a limited number of areas where wastewater customers are billed on a flat rate, meaning that unmetered customers receiving wastewater service from Aqua pay the same amount each month, *i.e.*, their water consumption does not have an effect on their monthly wastewater bills. Unmetered, flat-rate wastewater customers make up the communities of Tobyhanna, Pennsylvania (730 customers) and Lake Harmony, Pennsylvania (995 customers).[104] These communities were billed on a flat rate prior to Aqua's acquisition of these wastewater systems, and the Company has continued to bill the customers on a flat-rate basis. Aqua St. 9-R at 28.

There is no question that volumetric billing is preferable to flat-rate billing, as it provides better price signals and promotes conservation, as well as resulting in a more equitable distribution of the variable costs of wastewater service among ratepayers. However, in situations, such as this, where metered water information is unavailable, we acknowledge the standard industry practice of basing the flat rate on a system-wide average usage per month plus a customer charge. As indicated previously, Aqua assumes an average 5/8" meter residential customer uses 4,000 gallons per month.

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[104] Customers in Tobyhanna and Lake Harmony obtain their water supplies from individual wells not owned or operated by a utility or a municipality/municipal authority. Aqua St. 9-R at 28.

The flat charge should be reasonable and appropriate, and sufficient to cover the intended costs. The challenge is the development of a reasonable flat-rate charge. In this regard, we cannot ignore the disparity in the rates charged to metered and unmetered customers in certain divisions where Aqua serves both types of customers, as illustrated by the OCA. For these reasons, we agree with the ALJ's recommendation that directs Aqua to study and report the results in the next base rate proceeding, in order to determine whether different methods of calculating a flat rate would be more reasonable for some systems rather than applying a system-wide average to each system. Accordingly, Aqua Exception No. 10 is denied.

The primary concern at the public input hearings voiced by customers receiving wastewater service in the Tobyhanna and Lake Harmony service areas, including Mr. Osinski, was that flat-rate billing is unfair to customers with below average usage, including customers who may be part-time residents that may use less than full-time residents. *See* Tr. at 70-71, 166-68, 175-81, and 323-25. Recognizing that customers in Lake Harmony have private water wells on their property that are not individually metered, the OCA proposed a pilot program in Lake Harmony to install meters: (1) on an opt-in basis for those customers that request metered wastewater service, (2) on other customer-owned wells based upon a random sample of 10% to 20% of the unmetered customers. *See* OCA St. 4 SUPP. at 2.

Although we find merit in the OCA's proposal that Aqua study whether a different method of calculating a flat rate would be more reasonable for some systems than applying a system-wide average, we cannot say the same for its Lake Harmony pilot program proposal. Instead, we find persuasive the testimony of Aqua's witness, Ms. Heppenstall, explaining the impracticability of the OCA's proposal:

> I disagree for two reasons. One, the Company does not have the authority to meter a representative sampling of customer owned private wells. Allowing customers to opt in would

> only incentivize those customers with low water consumption, not the perceived larger users. Second, there are concerns about the ability to access customers' property to properly install a meter on a well. I understand that Company Witness Todd Duerr will explain the operational issues with this pilot program in his rebuttal testimony ([Aqua St. 9-R]). There may be substantial cost involved, and Mr. Watkins' proposal is that the Company bear the cost of such installations. Finally, the lack of authority to meter all privately owned wells means that the "pilot" can never be adopted as a permanent solution. Customers would continually opt for the lesser cost alternative. Mr. Watkins' proposal is unworkable.

Aqua St. 5-R at 17-18. We also find it difficult to ignore the operational issues with the OCA's proposal, highlighted by Aqua's witness, Mr. Duerr:

> First, we reinforce that industrywide flat sewer rates have been utilized to bill for public or private wastewater service in instances where customers have private wells throughout the Commonwealth. While we understand the customer's desire to limit any rate increase, resorting to changing the current methodology on which these customers are billed will not impact that reality, and in fact, some customers could be billed more. For wastewater only customers that receive water from private wells, the Company would be required to enter, traverse, and locate a customer's water well, to a property the Company does not have a right to enter, install a Company owned meter somewhere on a customer's property where a water well is located, and maintain that property going forward. That in and of itself is problematic.

Aqua St. 9-R at 29-30.

Regarding Mr. Osinski's assertion that the well servicing his community is metered, Mr. Duerr explained that "the well, the water meter, and the water distribution system are owned by the community. There are not individual meters measuring usage to each customer's residence. As such, the Company cannot bill these individual customers based on usage from one community water meter." Aqua St. 9-R at 30-31.

Based upon our review of the record evidence, we agree with the recommendation of the ALJ that the OCA's proposal be rejected, as it is not clear that the cost of the OCA's proposed pilot will achieve overall benefits to Aqua's customers that will outweigh the costs. The OCA does not explain: (1) Aqua's authority to place a meter on a person's water line; (2) how higher-usage customers could be "incentivized" to opt-in in the future; nor (3) why wastewater cost of service should be increased to cover the cost of installing, maintaining, and reading water meters for wastewater service. As such, we find no basis to reverse the ALJ's recommendation. Accordingly, OCA Exception No. 14 and Mr. Osinski's Exceptions are denied.

With regard to the OCA's argument that the Company be required to study the feasibility of opening an irrigation or deduct metering program to Aqua's non-Cheltenham customers and file the results of the study no later than the Company's next base rate case, we agree with the ALJ that the OCA has not demonstrated that further study would yield better results. Aqua noted that further studies are not necessary because the results will be similar to the analysis presented by the Company in the instant base rate case. Further, Aqua noted that the installation of a meter to measure usage deductions will increase the revenue requirement and not reduce the revenue requirement subject to recovery. Aqua M.B. at 244-45. Moreover, beyond arguing that it is unaware if the Company has conducted any studies on irrigation metering, the OCA has not sufficiently demonstrated why the Company should be required to conduct an irrigation metering study at this time. Accordingly, we find the OCA's argument that the Commission require the Company to conduct an irrigation metering program study to be unpersuasive.

To the extent that the OCA contends that the ALJ did not sufficiently acknowledge the OCA's irrigation water meter study, we note that the ALJ was aware of the positions and arguments put forth by the OCA, including the studies recommended by the OCA; however, it is up to the ALJ to determine whether, and to what extent, further discussion and analysis is warranted. See 52 Pa. Code §§ 5.403, 5.404. Here, it appears that the ALJ did not believe that further consideration of these matters was necessary to agree with Aqua that no further study is necessary. Accordingly, we will deny OCA Exception No. 15.

E. Tariff Structure - Proposed Reconcilable Rider Mechanisms

1. Energy Cost Adjustment Mechanism (ECAM) and Purchased Water Adjustment Clause (PWAC)

In this proceeding, Aqua proposed two new reconcilable rider mechanisms in its Tariff Water No. 3 to recover the costs associated with its energy and purchased water costs. These riders are the Energy Cost Adjustment Mechanism (ECAM) and the Purchased Water Adjustment Clause (PWAC) which are described in more detail, below. Inasmuch as the Exceptions address the ECAM and PWAC in combination, we shall address the merits of the Exceptions on these two items in a single consolidated disposition at the end of this section.

a. ECAM

(1) Positions of the Parties

Aqua proposed to implement the ECAM in its Tariff Water No. 3 (Tariff Water No. 3, Original Pages 35-36) to ensure that it will recover all of the energy costs it purchases from natural gas and electric providers. Aqua St. 4 at 5; R.D. at 99. According to the Company, the ECAM addresses both increases and decreases in the energy rates charged by energy suppliers from whom the Company purchases natural gas and electricity. *Id.* The Company provided the following explanation on how it proposes to implement the ECAM:

> The mechanism would collect or refund any difference between the energy costs included in base rates from the Company's last rate filing and the actual energy costs incurred in the period of calculation. Within 60 days after the end of each calendar year, the Company would file a reconciliation of its actual costs to the amount recovered in base rates per actual thousand gallons sold as established in the last rate case. Any increase or decrease in these costs would be divided by the projected normalized volumes increased for growth to develop a volumetric surcharge/surcredit applied to metered customers in the following 12-month period. In this way, the Company is protected from uncontrollable increases in costs and customers will receive the benefit of decreases if those costs are less than those included in rates. The ECAM is included as a rider in the proposed tariff submitted with this filing and describes the mechanics of the clause. At the end of a 12-month period, the amount refunded/collected via the mechanism would be compared to the actual costs to be refunded/collected and the difference would be added or subtracted to the difference to be recovered/refunded in the following period.

Aqua St. 4 at 6; Aqua M.B. at 255-256.

The Company is of the opinion that the ECAM and PWAC are authorized under Section 1307 of the Code and, thus, qualify as an exception to the general prohibition of single-issue ratemaking.[105] The Company argued that the ECAM is similar

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[105] In this case, as discussed below, the statutory advocates argued that the ECAM would constitute "single-issue ratemaking" because, if the ECAM were approved, the Company would be permitted "to automatically change customers' prices (rates) due to changes in single cost components." OCA St. 4 at 24.

to where other utilities are permitted to pass certain costs through a rider or surcharge as authorized by Section 1307 of the Code. Aqua St. 4-R at 2. The Company proposed that the same safeguards it proposed for its PWAC also apply to its ECAM, with the exception of the 3% billing cap. Aqua M.B. at 256, n.93. According to the Company, the Commission has approved similar clauses (*i.e.*, such as the State Tax Adjustment Surcharge (STAS) and the implementation of the reduced tax associated with the federal Tax Cuts and Jobs Act of 2017 (TCJA)) in circumstances where the costs are volatile, unpredictable, or significant. Aqua submitted that, if the PWAC is approved, its incentive to reduce operating costs will remain an important tenant of its regulatory compact with customers and regulators in the delivery of safe, adequate, and reliable utility service. Aqua St. 4 at 6; Aqua St. 4-R at 3. Similarly, the Company submitted that if the PWAC is approved, it would have ample incentive to take advantage of every reasonable opportunity to prevent increases and pursue decreases in its purchased water cost to the benefit of its customers. Aqua St. 4 at 5; Aqua St. 4-R at 3. In response to opponents who believe the ECAM and PWAC would discriminate in favor of competitive rate rider (CRR) customers and against all other customers because the proposed riders would not apply to CRR customers even though these customers are served, at least in part, with purchased water, the Company averred that the exclusion of contract customers from the operation of surcharges is not unduly discriminatory because the Commission has approved various surcharge provisions that exempt negotiated contract rate customers. Aqua St. 4-R at 4. The Company explained that CRR customers' contract prices would not change based on increases/decreases in the cost of purchased water or energy regardless of whether those changes are implemented through the PWAC or the ECAM or through changes in base rates. *Id.*

I&E, the OCA, and the OSBA each opposed the use of the proposed mechanisms for the recovery of energy expenses. R.D. at 100. According to I&E: (1) it is not appropriate to use a reconcilable rider such as the ECAM to recover O&M expenses because the energy expenses to be recovered via the ECAM are a minimal portion of routine O&M expenses for which the Commission must undertake a substantive audit and implementation task if it is approved;[106] (2) contrary to the Company's opinion, the ECAM would reduce the incentive for the Company to minimize its energy usage and minimize costs via shopping/negotiating for lower rates;[107] (3) Aqua failed to clearly explain how its claim for recovery of a routine operating expense through the ECAM mechanism would be appropriate;[108] (4) Aqua ignores the fact that the other utilities, to which it referred in direct testimony, are energy companies and those energy costs are pass-through gas and electric commodity costs, not expenses for energy consumed by those utilities during routine operations;[109] (5) the proposed ECAM is discriminatory because it would only apply to tariff rate customers and not rider rate customers;[110] (6) the Company has not shown that implementing the ECAM will result in the filing of fewer rate cases as it claimed, because the energy cost expense is not significantly volatile; nor is it a large enough expense to represent an extraordinary impact to the Company's operational output;[111] (7) the ECAM will only apply to the Water Tariff, which is problematic because the Company either will inappropriately use the Water Tariff to reconcile wastewater expenses, or the Company will simply treat water and wastewater customers unequally (I&E St. 1 at 53); and (8) the Company's arguments that it reports earnings on a quarterly basis does not negate the single-issue ratemaking nature of the ECAM because the proposed surcharge would benefit Aqua by increasing revenue in lockstep with expense increases for specific individual expenses while circumventing the normal rate case process in which the full examination of all expenses and revenues would be evaluated simultaneously. I&E St. 3-SR at 10-11.

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106 I&E St. 1 at 52-53; I&E St. 1-SR at 3; I&E St. 1-SR at 67.

107 I&E St. 1 at 51; I&E St. 1-SR at 61.

108 See I&E St. 3-SR at 9-13.

109 I&E St. 1 at 51-52; I&E St. 1-SR at 65.

110 I&E St. 3 at 23-24; I&E St. 3-SR at 11-13.

111 I&E St. 3 at 22-23; I&E St. 3-SR at 9-13.

The OCA echoed I&E's arguments and emphasized that Aqua's ECAM proposal amounts to single-issue ratemaking. OCA St. 4 at 24-25. The OCA submitted that the costs to be recovered through the ECAM do not warrant special recovery separate and apart from other costs recovered through base rates. OCA St. 4 at 25. The OCA notes that Aqua has exercised some control of purchased energy costs through its selection of suppliers (*See* Aqua Exh. 1-A, Schs. C-6.1.i., C-6.1.ii.) and has already captured the potential for future changes in purchased water and energy costs as part of its adjustments to its FPFTY claims. OCA St. 4 at 25; *see* Aqua Exh. 1-A, Schs. 6.1, 7.1.

The OSBA also agreed with I&E and the OCA that since the ECAM would make the Company whole for all energy cost increases between base rate proceedings, the ECAM would constitute single-issue ratemaking. OSBA M.B. at 6. The OSBA submitted that recovery of energy costs through the ECAM is unreasonable because the Company would have no incentive to control its energy usage or costs because they would automatically be passed onto customers. OSBA St. 1 at 22. The OSBA further noted that the ECAM would insulate the Company from fluctuating energy costs, thereby lowering Aqua's business risk, which should result in a lower ROE for Aqua. *Id.* However, the OSBA indicated that the Company made no such proposal, and that by lowering Aqua's business risk, while not lowering the Company's ROE, the Company's shareholders are the entities that would most benefit from the ECAM proposal. OSBA St. 1 at 22. According to the OSBA, the only way ratepayers would benefit from ECAM is if energy costs decrease between base rate proceedings; but given the economic challenges due to rising energy costs as well as the ongoing impact of the COVID-19 pandemic, the OSBA urged the Commission to incentivize Aqua to aggressively control its energy costs by rejecting the ECAM proposal. OSBA M.B. at 6.

Aqua LUG agreed with the statutory advocates' arguments that the ECAM is nothing more than an unjust and unreasonable attempt at single-issue ratemaking that should be rejected by the Commission. In addition, the Aqua LUG argued that Aqua's circumstances with relation to its purchased water and energy expenses simply do not warrant the implementation of an automatic recovery mechanism, as the costs to Aqua for its purchases of water supplies do not constitute significant expenses that require adjustments between base rate cases. Aqua LUG M.B. at 5-6.

(2) Recommended Decision

The ALJ agreed with the statutory advocates and recommended that the ECAM for the recovery of energy costs be rejected. The ALJ found that Aqua is a large company with considerable buying power and there is no reason to believe that it cannot adequately control its energy costs through normal cost control mechanisms. R.D. at 101-02. The ALJ further found that incentivizing cost containment by including energy costs in base rates is more effective than relying on the notion of a "regulatory compact with customers and ratepayers in the delivery of safe, adequate, and reliable utility service." *Id.* (citing Aqua St. 4 at 6). The ALJ noted that in the current economic climate, energy costs are not likely to decline, and this would be the only scenario where ratepayers would benefit from permitting the recovery of costs through a rider rather than through base rates. R.D. at 102.

The ALJ also agreed with the advocates that the ECAM equates to single-issue ratemaking. R.D. at 102. In support of this determination, the ALJ cited to a prior case involving a Collection System Improvement Charge (CSIC) rider in which the Pennsylvania Commonwealth Court declared that "single-issue rate making is prohibited if it impacts on a matter considered in a base rate case."[112] R.D. at 102 (citing *CSIC Order*). In *CSIC Order*, the Court ruled that "[t]he 'cursory' review undertaken for a

[112] *Popowsky v. Pa. PUC*, 869 A.2d 1144, 1152 (Pa. Cmwlth. 2005) (*CSIC Order*), appeal denied, 895 A.2d 552 (Pa. 2006) (citing *Phila. Elec. Co. v. Pa. PUC*, 502 A.2d 722, 727-28 (Pa. Cmwlth. 1985) (*PECO 1985*) and overturning Commission's grant of a wastewater utility's request to implement a CSIC).

surcharge is not a substitute for the review undertaken in a base rate case to determine whether a rate is just and reasonable." R.D. at 102 (quoting *CSIC Order*, 869 A.2d at 1157). Thus, the ALJ ruled that "[i]t is inappropriate to single out this cost for rate recovery without recognizing other possibly offsetting changes in costs and revenues that could ordinarily be thoroughly examined in a base rate proceeding, as Aqua's claims of expenses and offsetting savings and revenues are being examined in the instant case." R.D. at 102. The ALJ explained that to do so would violate the ratemaking principle of matching revenues, expenses, return and rate base. R.D. at 102 (citing OCA St. 3 at 15-16).

The ALJ concluded her recommendation with regard to the ECAM by noting that the financial risk of greater energy bills serves as an incentive to Aqua to seek methods to reduce its energy costs, whether through shopping for competitive suppliers or implementing other cost-saving conservation measures. R.D. at 102.

b. PWAC

(1) Positions of the Parties

Aqua proposed to implement the PWAC in its Tariff Water No. 3 (Tariff Water No. 3, Original Pages 37-38) that would enable the Company to recover the costs of water it purchases for resale from non-affiliated suppliers. Aqua St. 4 at 2. According to the Company, the rider addresses both increases and decreases in the price it pays for purchased water. *Id.* at 2-3. If rates are increased, the Company cannot recover those costs until the next rate case is filed; if rates are decreased, the customer must wait until the next rate case to benefit from that reduced cost. *Id.* at 3. Additionally, the Company proposed to include a 3% cap to its proposed PWAC as well as an audit and reconciliation process to protect its customers from unjust and unreasonable rates. *Id.*

The Company provided the following explanation on how it proposes to implement the PWAC:

> The PWA[C] would adjust customers' bills by adding a charge or credit to reflect increases or decreases, respectively, in the Company's "Baseline Cost." The Baseline Cost is the annual purchased water costs approved as an operating expense in the Company's last base rate case. When one or more of the Company's suppliers change the rates for water purchased by the Company, the Company will re-compute its annual purchased water costs based on the level of consumption and other billing determinants that formed the basis for the Company's calculation of its Baseline Cost. If there is a change in purchased water costs above or below the Baseline Cost, a charge or credit, as applicable, would be added to customers' bills. More precisely, the PWA[C] provides the Company the ability to implement a charge to recover an increase in purchased water costs above the Baseline Cost or a credit to pass back savings from a decrease in purchased water costs below the Baseline Cost.

Aqua St. 4 at 3-4; Aqua M.B. at 248-49.

As noted, Aqua proposed the PWAC to address both increases and decreases in the rates charged by non-affiliated suppliers from whom the Company purchases water. R.D. at 102 (citing Aqua St. 4 at 2); Aqua Tariff Water-PA P.U.C. No. 3 at 37-38. Aqua's PWAC proposal relies, in part, on the Commission's prior approval of a similar recovery mechanism for Newtown Artesian Water Company in 2010.[113] The Company noted that the PWAC for Newtown Artesian Water Company contained safeguards, and that it has proposed those same safeguards for the PWAC in this proceeding. *See* Aqua M.B. at 249, n. 88, which delineates the four safeguards.

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[113] *Pa. PUC v. Newtown Artesian Water Co.*, Docket No. R-2009-2117550 (Order entered April 15, 2010) (*Newtown Artesian Water*) at 6-17 affirmed by *Popowsky v. Pa. PUC*, 13 A.3d 583 (Pa. Cmwlth. 2011) (*Popowsky 2011*).

The statutory advocates have raised most of the same arguments against the PWAC that they made against the ECAM. R.D. at 103. As with the ECAM, I&E argued that the PWAC is discriminatory and that Aqua has not provided a convincing reason for treating purchased water expenses as anything other than an O&M expense which should be recovered in base rates. *Id.* (citing I&E St. 3 at 14). I&E asserted that the Company's request to use the PWAC to recover future increases in purchased water through a reconcilable surcharge is an unreasonable exception to the normal rate making treatment for purchased water expense and would violate the principle of "single issue ratemaking." *Id.* Aqua M.B. at 250. I&E submitted that in the past, the Commission only granted surcharge treatment when a utility has demonstrated that the expense in question was volatile or unpredictable and the level of the expense is significant when compared to total O&M expenses including depreciation expense. *Id.* However, in this case, I&E asserted that Aqua failed to present sufficient evidence that its purchased water expense is volatile, unpredictable, or significant.[114]

The OCA added that purchased water costs are known and are subject to agreements with the provider. OCA St. 4 at 25. Since Aqua has voluntarily entered into its contracts to purchase water with various entities, the OCA contended that those costs are not entirely beyond its control.[115]

The OSBA observed that like the ECAM, allowing Aqua to use the adjustment clause would not incentivize the Company to control its purchased water costs and the only way that ratepayers would benefit would be if purchased water costs declined between rate cases. OSBA St. 1 at 25. In addition, the OSBA's witness, Mr. Kalcic, argued that the PWAC was biased in favor of shareholders and would

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[114] *See* I&E St. 3 at 11-19 and I&E St. 3-SR at 7-8 for a full discussion of the PWAC issue.

[115] *See*, *e.g.*, Aqua Exh. 1-A, Sch. C-7.1.i. Also, *see* OCA St. 4 at 24-25 for a full discussion of the OCA's position on the ECAM and PWAC.

insulate Aqua's earnings. OSBA St. 1 at 22-25. Finally, the OSBA asserted that PWAC is unnecessary because the Company's purchased water costs are $4.5 million, whereas Aqua's claimed water cost of service is $575.03 million. Purchased water costs are only 0.7% of the Company's total costs. Any changes in water costs will have a minimal impact on Aqua's earnings. OSBA St. 1 at 24.

(2) Recommended Decision

The ALJ recommended that Aqua's proposed PWAC be rejected because Aqua failed to demonstrate that the PWAC is necessary, just, or reasonable. R.D. at 102-04. In reaching her decision, the ALJ relied on the arguments proffered by the statutory advocates which included many of the same arguments made in opposition to the ECAM.

The ALJ initially found that Aqua did not provide any convincing reasons why purchased water expenses should be treated as anything other than an O&M expense that are recoverable in base rates. R.D. at 103. The ALJ agreed with I&E that the Company's request for an exception to the normal ratemaking treatment for purchased water expense through a reconcilable surcharge is unreasonable based on past policy where the Commission only granted surcharge treatment when it had been demonstrated that the expense in question was volatile or unpredictable, and the level of the expense was significant when compared to total O&M expenses, including depreciation expense. R.D. at 103 (citing I&E St. 3 at 14). The ALJ found that Aqua did not present any such evidence related to its purchased water expense. R.D. at 103 (citing I&E St. 3 at 11-19; I&E St. 3-SR at 7-8).

Next, the ALJ concluded that Aqua's purchased water costs are not entirely beyond its control in that Aqua's purchased water costs are known costs because they are subject to agreements with the provider. R.D. at 103 (citing Aqua Exh. 1-A, Sch. C-7.1.i). The ALJ also concluded that permitting Aqua to use the PWAC would not incentivize the Company to control its purchased water costs and the only way that ratepayers would benefit would be if purchased water costs declined between rate cases. R.D. at 103. The ALJ further found that the PWAC is not necessary because any changes in water costs will have minimal impact on Aqua's earnings since the Company's purchased water cost of $4.5 million is only 0.7% of its total claimed water cost of service of $570.03 million. R.D. at 104 (citing OSBA St. 1 at 24).

Finally, the ALJ ruled that Aqua's reliance on *Newtown Artesian Water* is misplaced. R.D. at 104. In support of her judgment, the ALJ explained:

> At the time of its request, Newtown purchased nearly 60% of its water from other sources. [*Newtown Artesian Water* at 3] Its purchased water expense represented about 25% of its annual revenues and 34% of its O&M expenses for the same period. [*Newtown Artesian Water* at 3; *see also* I&E St. 3 at 18-19; I&E Exh. 3, Sch. 3 at 1-2] In stark contrast, Aqua's projected purchased water costs will amount to only about 0.7% of its total water cost of service. [OCA St. 4 at 25] Aqua is not a small utility where purchased water or energy costs constitute a significant portion of its cost of service. Aqua's costs are not so significant such that they would cause its overall cost of service to vary widely from authorized revenues as a result of suppliers' price changes. Similar to ECAM, the financial risk of greater purchased water bills serves as an incentive to Aqua to seek methods to reduce its purchased water costs, whether through shopping for competitive suppliers, supplying more of its own water, reducing water losses, or implementing other cost-saving conservation measures. Aqua has failed to demonstrate that the PWAC is necessary, just or reasonable.

R.D. at 104 (footnote numbers omitted).

c. Aqua Exception No. 11 and Replies

In its Exception No. 11, Aqua disagrees with the conclusions the ALJ reached in support of her recommendations that the proposed ECAM and PWAC be rejected. Aqua Exc. at 35-36; R.D. at 99-104. Those conclusions include: (1) the ECAM and PWAC constitute impermissible single-issue ratemaking (R.D. at 102); (2) the Company failed to demonstrate that it cannot adequately control its energy and purchased water costs through normal mechanisms (R.D. at 101-102; 104); (3) the Company's energy and purchased water costs each do not constitute a significant amount of Aqua's cost of service (*Id.*); and (4) customers are not likely to benefit from the ECAM because energy costs are not, likely to decline in this climate (R.D. at 102). For the reasons discussed below, the Company requests that the above findings be rejected and each of the reconcilable riders be approved.

First, Aqua maintains its position that the two new reconcilable riders should be approved because it has demonstrated that they satisfy the requirements for approval of reconcilable riders under Pennsylvania law and Section 1307(a) of the Code. Aqua Exc. at 36 (citing Aqua M.B. at 245-249; Aqua R.B. at 105-106). Additionally, Aqua submits that because each rider seeks to recover an expense that is easily identifiable and beyond the Company's control, it has adequately demonstrated that the ECAM satisfies the exception to the prohibition against single-issue ratemaking. Aqua Exc. at 36.

The Company also disagrees with the ALJ's finding that energy costs are not likely to decline. The Company contends that the ALJ's statement is an unsupported assertion used to undermine Aqua's otherwise unrebutted testimony that any energy cost savings would be passed through to customers in a timely manner. *Id.*

In view of the above arguments, the Company requests that, for the reasons more fully explained in its Briefs, the Commission reject the ALJ's findings and approve the proposed ECAM. Aqua Exc. at 36 (citing Aqua M.B. at 235-58; Aqua R.B. at 105-07). We refer to the "Positions of the Parties" sections, above, which address the Company's positions with regard to the issues it raised in its Exceptions here concerning these ECAM and PWAC riders.

In its reply, I&E disagrees with the Company that its ECAM and PWAC riders satisfy the requirements under Pennsylvania law and Section 1307(a) of the Code. I&E also submits that Aqua continues to aver, incorrectly, that the proposed reconcilable riders satisfy the well-recognized exception to the prohibition against single-issue ratemaking, and that each rider seeks to recover an expense that is easily identifiable and beyond the Company's control. I&E R. Exc. at 11.

In regard to the ECAM, I&E avers that the ALJ appropriately considered the counter arguments made by the statutory advocates and correctly recommended that the ECAM for the recovery of energy costs should be rejected. I&E R. Exc. at 11 (citing R.D. at 101). I&E agrees with the ALJ's reasoning that because Aqua is a large company with considerable buying power, there is no reason to believe that it cannot adequately control its energy costs through normal cost control mechanisms. In consideration of the above, and the fact that the ALJ concluded that the ECAM would equate to single-issue ratemaking, I&E believes Aqua's Exception should be denied. I&E R. Exc. at 11.

With regard to the PWAC, I&E opines that the ALJ correctly agreed with the statutory advocates by rejecting the PWAC and recommending that Aqua continue to recover its purchased water costs in base rates rather than through the PWAC. I&E R. Exc. at 11 (citing R.D. at 103). I&E agreed with the ALJ that Aqua's purchased water cost, which amounts to only 0.7% of its total water cost of service, is not a significant portion of its total water cost of service. I&E R. Exc. at 11 (citing R.D. at 104). As such, I&E maintains that Aqua's costs are not so significant that they would cause its overall cost of service to vary widely from authorized revenues due to its suppliers' price changes. *Id.* I&E, therefore, asserts that since Aqua has failed to demonstrate that the PWAC is necessary, just or reasonable, the Commission should reject Aqua's Exception on this matter. I&E R. Exc. at 11-12.

In its reply to Aqua's Exception No. 11, the OCA renders similar arguments to those raised by I&E. OCA R. Exc. at 20-21. The OCA agrees with the ALJ to reject the ECAM because it constitutes single-issue ratemaking, and it is not appropriate to adopt this type of reconcilable rider mechanism because Aqua is adequately able to control its energy costs. OCA R. Exc. at 20 (citing R.D. at 101-02).

The OCA also submits that it supports the ALJ's recommendation to reject the PWAC because the ALJ correctly found that Aqua's reliance on *Newtown Artesian Water* was misplaced. OCA R. Exc. at 20 (citing R.D. at 103 and *Newtown Artesian Water* at 6-17). The OCA references the ALJ's Recommended Decision comparing Newtown with Aqua in which the ALJ stated that Newtown purchased nearly 60% of its water and that Newtown's expense was about 25% of its annual revenues and 34% of its operation and maintenance expenses. In contrast, Aqua's projected purchased water costs are only about 0.7% of its total water cost of service.[116] OCA R. Exc. at 20 (citing R.D. at 104; OCA M.B. at 114).

The OCA also requests that the Commission reject Aqua's continued stance in its Exceptions that Section 1307(a) justifies implementing the ECAM and PWAC because Aqua's energy costs and purchased water costs are outside of its control. In this regard, the OCA submits that Aqua's position is unsupported because, as the ALJ found,

[116] It is noted that the OCA appears to inadvertently state in its reply that Aqua's projected purchased water costs are about "1.4% of its total water cost of service."

due to the large size of Aqua, which has considerable buying power, there is "no reason to believe that it cannot adequately control its energy costs through normal cost control mechanisms." OCA R. Exc. at 21 (citing R.D. at 101). Since Aqua has voluntarily entered into contracts to purchase water with various entities, the OCA contends that those are known costs for which Aqua can exercise some control. *Id.* The OCA also notes that Aqua has exercised some control through its selection of electricity suppliers. OCA R. Exc. at 21 (citing OCA R.B. at 69).

The OCA concludes its reply by asserting that the costs at issue in the ECAM and PWAC do not meet the criteria that the Commission and Courts have applied in approving a Section 1307(a) surcharge. OCA R. Exc. at 21 (citing OCA R.B. at 70-71). In this regard, the OCA argues that the associated costs are not extraordinary, substantial, unexpected, or non-recurring. Instead, the OCA opines that such costs represent the normal, ongoing costs of providing water service that are such a small percentage of Aqua's overall cost of service that any fluctuations will have minimal impact. OCA R. Exc. at 21.

In its reply to Aqua's Exception No. 11, the OSBA makes similar arguments as I&E and the OCA that Aqua's ECAM and PWAC do not satisfy the requirements of Section 1307(a) of the Code. OSBA R. Exc. at 4, 5. The OSBA also disagrees with the Company's argument that the proposed riders qualify as a "well recognized exception to the prohibition against single-issue ratemaking" because each of them would move consideration of a *single* ratemaking expense outside the context of a traditional base rate proceeding. OSBA R. Exc. at 3, 4, 6 (citing Aqua Exc. at 36). The OSBA submits that the ECAM and PWAC are classic examples of single-issue ratemaking and would provide no incentive to control its energy and purchased water costs because the ECAM, in particular, would insulate the Company from fluctuating energy costs, and any energy and purchased water cost increases under the ECAM and PWAC, respectively, would be passed along to customers. OSBA R. Exc. at 4, 5.

The OSBA also reinforces its previous argument that the ECAM would lower Aqua's business risk, which should lower its ROE. The OSBA notes that the Company did not make such a proposal in this rate proceeding. Accordingly, the OSBA remains of the opinion that if the Company's ROE is not lowered in conjunction with the resulting lower business risk, the approval of the ECAM rider would only serve to benefit the Company's shareholders. OSBA R. Exc. at 4 (citing OSBA St. No. 1 at 21-22).

d. Disposition

After thoroughly reviewing the record with respect to the ECAM and the PWAC, we shall deny Aqua's Exception No. 11 and adopt the ALJ's recommendations that reject the two reconcilable rider mechanisms in accordance with the arguments set forth by I&E, the OCA, the OSBA and Aqua LUG in this proceeding.

The primary disagreement between the Company and the opposing Parties centers on whether the tariffed ECAM and PWAC riders satisfy the requirements for approval of reconcilable riders under Pennsylvania law and Section 1307(a) of the Code. I&E, the OCA, the OSBA and Aqua LUG (opposing Parties) were opposed to these riders and argued that approving them would constitute impermissible single-issue ratemaking. I&E M.B. at 91-95; OCA M.B. at 112-15; OSBA M.B. at 5-7; Aqua LUG M.B. at 4-6. Aqua, however, took the position that Section 1307(a) specifically provides an exception to the prohibition against single-issue ratemaking, and that Aqua's proposal to add the riders is almost identical to the rider proposed and approved in *Newtown Artesian Water*. Aqua R.B. at 105. Aqua also submitted that I&E's, the OCA's, and the OSBA's attempts to distinguish this case on the basis that Aqua's cost are not as significant as in *Newtown Artesian Water* also fail.[117] The Company argued that while

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[117] *See* Aqua R.B. at 105, n.41 OCA M.B. at 114; I&E M.B. at 92, 94; OSBA M.B. at 6-7.

the court in *Popowsky 2011* recognized that *Newtown Artesian Water* purchased a significant portion of its water from other sources, precedent clearly demonstrates that where an automatic adjustment clause is not specifically authorized by statute, a utility must show that the expense is easily identifiable and beyond the utility's control.[118] Thus, Aqua contends that it has made this showing. Aqua R.B. at 105-06, n.41.

Upon our review of the record, we are not persuaded by the Company's arguments that there is a need to implement the ECAM and PWAC in this proceeding. First and foremost, we agree with the ALJ and the opposing Parties that granting Aqua's request to adopt the riders constitutes single-issue ratemaking because the costs that Aqua proposes to recover through the reconcilable surcharges apply to costs that are normal, ongoing costs of providing water service. Therefore, because we find that the costs are not unique, unexpected, or non-recurring, we conclude that it would not be prudent to permit the Company to use the Section 1307(a) statute to justify its requests for the proposed riders because the Company has not persuaded us that it has experienced any extraordinary circumstances with regard to its purchased water and energy costs when compared to the other routine O&M costs it recovers through base rates.

We also disagree with the Company's contention that since the Commission approved a similar rider in *Newton Artesian Water*, the Commission should approve its proposed riders in this proceeding. Our review of the record indicates that there is a major difference between the rider approved for *Newtown Artesian Water* and those proposed here. According to testimony presented by I&E's witness, Mr. Esyan Sakaya, "unlike Aqua's situation, Newtown purchased approximately 52% of the water sold in the first half of 2009 from the Bucks County Water Authority (I&E Exh. No. 3, Sch. 3, p.1)" and "[t]he purchased water expense was over 29% of total O&M and depreciation expense for the same period (I&E Exh. No. 3 Sch. 3, p.2)." I&E St. 3 at 18.

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118 *See* Aqua M.B. at 245 (citing, in part, *Popowsky 2011*).

Here, the record indicates that Aqua only purchases 2.46% of the total water it sells. Mr. Sakaya further testified:

> The total proposed purchased water expense claim is $4,135,311 (Aqua Ex. No. 3, Sch. C-7 1.i). Subtracting the affiliated purchases of $297,839 leaves $3,837,472 ($4,135,311 - $297,839) of non-affiliated purchase water expense. The total Operating, Maintenance and Depreciation expense for the Company is approximately $272,527,954 (Aqua Ex. 5-A, Sch. C, column 2, line 4, p. 9). Therefore, non-affiliated purchased water expense is only 1.4% ($3,837,472 / $272,527,954) of total operating, maintenance and depreciation expenses. This 1.4% is minimal compared to the 24% - 70% of purchased gas costs that is typical for a natural gas utility with a PGC adjustment.

I&E St. 3 at 16. We note that the OSBA's witness, Mr. Kalcic, testified that based on the $4.15 million in total purchased water expense claim in this proceeding, "[t]he Company's total claimed cost of service for its water operations (excluding Act 11) is $575.03 million. As such, Aqua's claimed purchased water expense amounts to only 0.7% of its total costs." OSBA St. 1 at 24.

With regard to the Company's purchased power expense the Company proposes to recover through the ECAM, Mr. Sakaya testified:

> [T]he total proposed purchased power expense, projected for the FPFTY ending March 31, 2023 is $8,182,196 (AP Ex. No. 1-A, Sch. C-6.1, line 3). The total Operating, Maintenance and Depreciation expense for the Company is approximately $272,527,954 (AP Ex. 5-A, Sch. C, column 2, line 4, p. 9). Therefore, purchased power expense is only 3.0% ($8,182,196 / $272,527,954) of total Operating, Maintenance and Depreciation expenses. This 3.0% is nowhere near the 24% - 70% that is typical for gas utilities with a PGC adjustment. Even large variations in an expense of this size

> would not represent an extraordinary impact to the Company's operational outlook.

I&E St. 3 at 23. Using Mr. Kalcic's comparison that he calculated for the Company's total percentage of purchased water to the Company's total cost, we calculate that the Company's claimed purchased energy costs amounts to only 1.4% of its total costs [($8,182,196 ÷ $575,030,000) x 100 = 1.4%].

In view of the above comparisons, our approval of the reconcilable rider for *Newton Artesian Water* does not justify approving the ECAM and PWAC riders in this proceeding as argued by Aqua. The *Newtown Artesian Water* case is a rare exception where we determined such a rider was absolutely necessary because of the extraordinary circumstances in that case. Such circumstances are not relevant with regard to the Company's purchased water and energy costs in this proceeding. As the ALJ and the opposing Parties appropriately observed, these expenses are routine O&M expenses that are not unique, unexpected, or non-recurring. R.D. at 100-02. Thus, we are of the opinion that granting the Company's request to adopt its ECAM and PWAC reconcilable riders would be akin to single-issue ratemaking. As emphasized by the Commonwealth Court, single-issue ratemaking is similar to retroactive ratemaking and is generally prohibited if it impacts on a matter normally considered in a base rate case such as this proceeding. *See Popowsky 2011*, 13 A.3d at 593. Additionally, we agree with the ALJ that to approve the proposed riders "would violate the ratemaking principle of matching revenues, expenses, return and rate base." R.D. at 102. Accordingly, the Company's *Newtown Artesian Water* argument in its Exceptions is denied.

Regarding the Company's Exception to the ALJ's ruling that Aqua failed to demonstrate that it cannot adequately control its energy and purchased water costs through normal mechanisms, we again are not persuaded by the Company's arguments. The Company has not submitted any convincing historical data demonstrating erratic fluctuations in its water or energy costs between rate cases that would persuade us that such costs are beyond the Company's control. In fact, the record demonstrates otherwise. I&E witness, Mr. Sakaya, testified that historical data submitted by the Company "shows no significant price volatility from municipal water suppliers from 2019 to 2023." I&E St. 3-SR at 13 (citing Aqua Exh. 1-A(a), Sch. C-7.1.1.). Mr. Sakaya also noted that "the cost of purchased water on a cost per unit basis generally increases from rate case to rate case like many other expenses, such as payroll and benefits, but it is not volatile and subject to large unanticipated increases or decreases." I&E St. 3 at 15. The fact that the Company's purchased water and energy expenses are not volatile or unpredictable makes it easier for the Company to control its costs. In this regard, we agree with the OCA's position that because the Company's purchased water costs are known and subject to contractual agreements with various entities, Aqua's costs are not entirely beyond its control.

We also agree with the ALJ's evaluation of this matter when she stated the following with regard to the ECAM:

> As the advocates observe, Aqua is a large company with considerable buying power. There is no reason to believe that it cannot adequately control its energy costs through normal cost control mechanisms. Incentivizing cost containment by including energy costs in base rates is more effective than relying on the notion of a "regulatory compact with customers and ratepayers in the delivery of safe, adequate, and reliable utility service."

R.D. at 102.

In light of the above, we conclude that Aqua has unreasonably requested an exception to the normal rate making treatment for purchased water and energy expenses by requesting that future increases be automatically recovered through a reconcilable surcharge. Accordingly, Aqua's Exception No. 11 is denied and the ALJ's recommendation is adopted in its entirety with regard to the proposed ECAM and PWAC.

2. Federal Tax Adjustment Surcharge

a. Positions of the Parties

Aqua proposed to add a new reconcilable surcharge, entitled the Federal Tax Adjustment Surcharge (FTAS), to its water and wastewater tariffs (Tariff Water No. 3, Original Pages 32-34, and Tariff Sewer No. 3, Original Pages 16-19) which will adjust its water and wastewater base rates when there are changes in federal corporate income tax rates by adding the revenue requirement for the incremental impact of the change in the federal corporate income tax rate. Aqua St. 8 at 14-15.

Aqua explained that the FTAS is analogous to the State Tax Adjustment Surcharge (STAS) that the Company, and other major Pennsylvania utility companies, have had in place for many years, and just as the STAS provides for adjustments to base rates for changes in state taxes (and more specifically for changes under the Pennsylvania Corporate Net Income Tax), so too does the FTAS provide for adjustments to base rates for changes in federal corporate income tax. Aqua St. 8 at 18.

According to the Company, the FTAS was proposed because significant changes in the federal corporate income tax rate can substantially impact the Company's revenue requirement and it is more appropriate to adjust rates quickly to reflect significant federal tax rate changes. Aqua St. 8 at 15, 17. The Company cited the TCJA as an example to describe the difficulty and delays of implementing federal corporate tax rate changes in the current environment. Aqua St. No. 8 at 17. The Company explained that for companies like Aqua that had planned base rate cases in 2018, the lower tax rate was reflected in those decisions prospectively in early 2019, along with refunds for 2018.

Id. The Commission set temporary rates for other companies and implemented surcredits[119] on July 1, 2018, to begin the flow through of the tax rate decrease and required those companies to record regulatory liabilities for the first half of 2018. *Id.* This process delayed receipt of the effects of the tax rate change and required changes to rates previously charged for service. *Id.* The Company expressed its concerns that the White House recently has proposed an increase in the corporate tax rate from 21% to 28% and, if enacted, this will roll back some tax reductions enacted only a few years ago. *Id.* at 15. The Company presented an analysis showing the effect the potential corporate tax increase would have on its revenue requirement. *Id.* at 16-17. The Company opined that any delay in adjusting rates can result in either significant refunds or retroactive collections after the effective date of the tax rate change and may compel Aqua to file another rate case sooner than originally planned at significant cost and time to all parties. *Id.* at 15, 16. The Company averred that the FTAS will avoid these concerns because it is designed to adjust rates as fast as possible to reflect tax rate changes. *Id.* at 18.

I&E opposed the FTAS. According to I&E, the Company's stated need for the surcharge is speculative as the Company cannot say with certainty if or when an increase to the federal corporate income tax rate might be enacted or ever take effect. I&E St. 1-SR at 32-46. Furthermore, the Commission and its advisory staff have appropriately responded to changes in tax law as they have recently dealt with this issue in response to the reduction in the federal corporate income tax rate that took effect starting January 1, 2018, because of the TCJA. *Id.* at 32. I&E is confident that the Commission would provide adequate and timely guidance on a statewide basis to affected regulated utilities if such a tax rate change occurs. Accordingly, I&E opined that there is no need for the proposed FTAS at this time.

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[119] Generally, a "surcredit" is a surcharge returned to a customer.

I&E also had concerns about allowing rate adjustments in a surcharge mechanism for excess ADIT because deferred taxes require more scrutiny of regulators and statutory parties due to subjectivity in certain circumstances in determining the proper normalization periods, particularly for tax differences associated with non-protected assets that are not subject to the strict requirements of IRS normalization rules. *Id.* at 33-39. In addition, I&E testified in favor of a one-sided interest component for a reconcilable rider where the Company must pay interest to ratepayers for excess tax amounts due to be refunded to ratepayers so that companies would be encouraged to promptly refund its customers. I&E St. 1-SR at 39-40.

The OCA also opposed the implementation of the FTAS. OCA St. 2 at 14-15. The OCA submitted that the Company's proposal to implement the FTAS is premised on Aqua's belief that the federal corporate income tax rate may be increased from 21% to 28%, but it is uncertain when the next change in the corporate federal income tax rate will occur, and whether the legislation enacting the change will include other provisions which affect corporate federal income tax liabilities. *Id.* at 15. Based on the provisions attached to the TCJA (*i.e.*, the tax treatment of net operating loss carryback and caps, and limits on net interest deductions), the OCA asserted that such provisions need to be given consideration before they are allowed. *Id.* According to the OCA, the FTAS is neither necessary nor reasonable because it is unknown when or even if the federal government will make legislative changes to the federal tax rate. *Id.* The OCA concluded that any changes to the federal corporate income tax rate should be addressed by the Commission on a generic basis. *Id.* at 16.

b. Recommended Decision

The ALJ agreed with I&E and the OCA that Aqua's proposed FTAS should be rejected because it is uncertain when the next change in the federal corporate income tax rate will occur, and it is unknown whether any future legislation enacting a change in

the federal corporate tax rate would include other provisions which would affect tax liabilities. The ALJ stated that, at this time, there is no pending legislation proposing an increase to the federal corporate income tax rate, and even if legislation was being considered in Congress, there is no way of knowing if or when and in what form the tax change would be implemented. The ALJ concluded that, while it may be true that changes in tax rates may affect utilities differently, the FTAS proposal is premature and should be rejected because there is no current legislation to actually consider, and Aqua is requesting a surcharge mechanism with no trend or context in which to evaluate it.
R.D. at 106.

c. Aqua Exception No. 12 and Replies

In its Exception No. 12, the Company believes the ALJ erred in rejecting the proposed FTAS. Aqua Exc. at 36. First, Aqua opines neither the ALJ nor any of the other Parties found or concluded that the proposed method of calculation, mechanics, or safeguards contained in the FTAS were unreasonable. Aqua Exc. at 37 (citing Aqua M.B. at 261, noting that no parties contested these aspects of the FTAS).

The Company believes that the ALJ's concern – that a change in the federal corporate income tax rate is uncertain – is irrelevant to the determination of whether the FTAS is just and reasonable, because "if no change occurs, the FTAS has no impact upon customers," and "if/when a change does occur, the FTAS will act as a temporary mechanism if/when a change occurs between a utility's base rates and will more-timely ensure that the impacts of the change are reflected in the utility's rates." Aqua Exc. at 37 (citing Aqua M.B. at 262; Aqua St. 8-R at 9).

Aqua also argues that it has demonstrated that any change in the federal corporate income tax rate would have a significant impact upon tax expense, and the Company's rates. The Company estimates that an increase in the federal corporate income tax rate from 21% to 28% would result in a $14 million increase in its revenue requirement. Aqua Exc. at 37 (citing Aqua St. No. 8 at 1). The Company avers that this calculation is unrebutted; therefore, it is reasonable to infer that any changes in the federal corporate income tax rate, whether an increase or a decrease, will significantly impact the Company's base rates. Aqua Exc. at 37.

Aqua also reiterates its analogy of its proposed FTAS with the existing STAS mechanism in that "[j]ust as the STAS provides for adjustments to base rates for changes in state rates (and more specifically for changes under the Pennsylvania Corporate Net Income Tax), so too does the FTAS provide for adjustments to base rates for changes in federal corporate income tax." Aqua Exc. at 37-38 (citing Aqua St. 8 at 18).

In reply to Aqua Exception No. 12, I&E first disagrees with the Company's representation that the ALJ "did not find or conclude that the proposed method of calculation, mechanics, or safeguards contained in the FTAS were unreasonable." I&E R. Exc. at 12 (citing Aqua Exc. at 37). I&E submits that the ALJ did not have to consider whether the FTAS is reasonable because she concluded that the proposed FTAS is premature when she stated in her Recommended Decision that "at this time there is no pending legislation proposing an increase to the federal corporate income tax rate." I&E R. Exc. at 12 (citing R.D. at 106). I&E notes that the ALJ further concluded that "while it may be true that future changes in tax rates may affect utilities differently, there is no current legislation to actually consider and Aqua is requesting a surcharge mechanism with no trend or context in which to evaluate it." *Id.* In view of the fact that the ALJ made no determinations to find that the terms of the FTAS were reasonable, I&E submits that Aqua's Exception here should be rejected. *Id.*

In its reply, the OCA disagrees with Aqua's arguments in its Exceptions that the lack of evidence of any change in the federal tax liabilities is irrelevant, and that there would be a large impact on Aqua if there is a change in the federal income tax rate. OCA R. Exc. at 22 (citing Aqua Exc. at 36-38). The OCA contends that Aqua's arguments are without merit because, if the issue of tax liabilities is "irrelevant," then there is no reason to implement Aqua's proposed FTAS. *Id.* Thus, the OCA opines that Aqua's position is consistent with the evidence that establishes that the FTAS is not necessary. *Id.* Because Aqua has not presented any evidence that a tax change is imminent and its witness admitted that "no one can say with any certainty if/when an increase to the federal corporate income tax will take effect," the OCA argues that Aqua's proposed FTAS must be rejected. *Id.;* R.D. at 106 (citing Aqua St. 8-R at 10).

The OCA also takes issue with Aqua's argument that the impact of any tax changes would be large. OCA R. Exc. at 22. The OCA asserts that Aqua's statement is pure speculation because the Company has no knowledge or certainty of any upcoming tax changes. The OCA avers that the Company has presented its FTAS as the only way to address a hypothetical tax change. Nevertheless, the OCA stresses that future, unknown changes to the federal corporate income tax rate should be addressed by the Commission on a generic basis for all the public utilities similar to what the Commission did in February 2018, when it initiated a generic proceeding to determine the effects of the TCJA on public utilities' tax liabilities. *Id.* (citing OCA M.B. at 83; OCA St. 2 at 15).

d. Disposition

We agree with the ALJ's recommendation that the Company's proposed FTAS reconcilable rider should be rejected because it is premature, and no trend or context has been established under which it can be evaluated. In reaching our decision on this matter, we share the concerns of the ALJ and the opposing Parties that it is uncertain when the next change in the federal corporate income tax rate will occur, and it is unknown whether any future legislation enacting a change in the federal corporate tax rate would include other provisions which would affect tax liabilities. Thus, we agree with the ALJ that the FTAS proposal is premature because there is no current legislation to actually consider and Aqua is requesting a surcharge mechanism with no trend or context within which to evaluate it. *See* R.D. at 106. We further find that the FTAS is not necessary at this time because this Commission, in conjunction with our advisory staff, recently provided timely guidance on a statewide basis to the affected regulated utilities with regard to the method of calculation, mechanics, or safeguards on the methodology to use in implementing the federal corporate income tax rate that took effect starting January 1, 2018. *See Tax Cuts and Jobs Act of 2017*, Docket No. M-2018-2641242. In our opinion, the Commission may utilize this same process again should changes in the federal tax rate occur in the future. Furthermore, we support the OCA's position that any changes to the federal corporate income tax rate should be addressed by the Commission on a generic basis for all the public utilities under its jurisdiction because "future legislation changing the federal corporate income tax rates may impact other provisions which affect corporate federal tax liabilities." *See* OCA M.B. at 83.

For the reasons above, we shall deny Aqua's Exception No. 12 and adopt the ALJ's recommendation that rejects the Company's FTAS reconcilable rider it proposed in its water and sewer tariffs.

3. Universal Service Rider

a. Positions of the Parties

Aqua proposed to include a Universal Service Rider (USR) in its water and wastewater tariffs[120] that would adjust its residential base rates to recover the costs of its

[120] *See* proposed Tariff Water No. 3, Original Pages 32-34, and proposed Tariff Sewer No. 3, Original Pages 19-21.

proposed customer assistance programs (CAP) from all residential customers, except those enrolled in the Company's CAPs. Aqua explained that its proposed USR is similar to the riders in the tariffs of its affiliated Peoples Companies[121] and other energy utilities throughout the state and that it has filed the USR consistent with the terms of the *Aqua-Peoples Settlement*[122] that was approved by the *Aqua-Peoples Acquisition Order*.[123] R.D. at 107; Aqua M.B. at 264; Aqua St. 10 at 9; Aqua St. 2 at 17-18.

According to the Company, the USR will be used to recover those costs associated with the following low-income offerings: (1) CAP discounts; (2) CAP arrearage forgiveness benefits; (3) CAP administration by a third party (*i.e.*, Dollar Energy Fund); and, (4) the proposed Conservation and Emergency Repair Program ($100,000 per year). Aqua St. 10 at 9. Aqua's calculation of the costs to be recovered through the USR is based on its anticipated enrollment in the CAP, subject to an annual reconciliation and audit by the Commission. Aqua St. 10 at 10. Aqua submitted that approval of the USR will ensure that residential ratepayers are only responsible for actual costs of the program, rather than projected costs that may not come to fruition. *Id.*

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[121] The Peoples Companies include Peoples Gas Company, Peoples – Equitable Division, and Peoples Natural Gas Company LLC.

[122] *See Joint Petition for Approval of Non-Unanimous, Complete Settlement Among Most Parties*, Docket Nos. A-2018-3006061, A-2018-3006062 and A-2018-3006063; June 26, 2019 (*Aqua-Peoples Settlement*).

[123] *See Joint Application of Aqua America, Inc., Aqua Pennsylvania, Inc., Aqua Pennsylvania Wastewater, Inc., Peoples Natural Gas Company LLC and Peoples Gas Company LLC for All of the Authority and the Necessary Certificates of Public Convenience to Approve a Change in Control of Peoples Natural Gas Company LLC and Peoples Gas Company LLC by Way of the Purchase of All of LDC Funding, LLC's Membership Interests by Aqua America, Inc.*, Docket Nos. A-2018-3006061, A-2018-3006062 and A-2018-3006063 (Order entered Jan. 24, 2020) at 147-150 (*Aqua-Peoples Acquisition Order*).

The Company provided the following explanation on how its proposed USR will operate:

> The USR would adjust customers' bills by adding a charge or credit to reflect increases or decreases, respectively, in the Company's "Baseline Cost." The Baseline Cost is the estimate to administer and provide benefits under the various program components in the proposed CAP. Costs and revenues under the USR will be reconciled each year, and an over or under collection, as applicable, will be included in the "E" factor of the charge.

Aqua M.B. at 264; Aqua St. 2 at 18.

The OCA argued that the USR should not be approved for the following reasons: (1) any recovery of low-income program costs should be recovered in base rates rather than through a reconcilable rider, and the associated costs should be based on net costs, rather than gross costs (R.D. at 107; OCA St. 5 at 42); (2) it is not appropriate for Aqua to use the Peoples Companies' reconcilable riders as models to recover costs for its low-income programs because when the Commission approved the reconcilable riders for Pennsylvania gas and electric utilities, the Commission relied upon specific statutory language from Pennsylvania Energy Competition Acts,[124] which are not applicable to water/wastewater companies (*Id.* at 43-44); (3) the recovery of the low-income program costs should not be subject to a reconcilable recovery rider because CAP costs: (a) are normal operating costs that represent a small portion of Aqua's total operating revenues; (b) will not vary widely based on changes in total consumption as would occur with energy CAPs; and (c) are not variable costs that fluctuate outside of Aqua's control (*Id.* at 45); and (4) the Company proposed to recover the low-income program costs only from the residential customer class (*Id.* at 46).

[124] Electricity Generation Customer Choice and Competition Act, 66 Pa. C.S. § 2804(9); Natural Gas Choice and Competition Act, 66 Pa. C.S. § 2203(8) (collectively, the Energy Competition Acts).

I&E agreed with the Company in opposing the OCA's position that the Company's universal service program (USP) costs be recovered through base rates. I&E argued it is preferable that the Company's costs for a full-scale universal service plan be recovered via a reconcilable surcharge mechanism that tracks dollar-for-dollar net costs similar to what is used by the Peoples Companies. I&E St. 1-R at 3.

I&E also opposed the OCA's suggestion that only net costs[125] of the program be recovered via base rates because the OCA failed to address how the Company would not potentially over or under-recover associated net costs if projections are incorporated as a component of base rates which would not be updated until the Company's next base rate case filing. I&E St. 1-R at 3-4.

I&E made the following three recommendations with regard to the Company' proposed USP: (1) in view of the fact that, for the first time, the Helping Hand program will be funded by involuntary ratepayer funding, the Company should be required to perform income verifications to admit participants into the programs to ensure legitimacy of applicants and reduce misuse of the program. (I&E St. 1 at 45; I&E St. 1-R at 5; I&E St. 1-SR at 53); (2) the Company should be required to perform the appropriate tracking, to be reported in the Company's next base rate case filing, that demonstrates its efforts to encourage participants to take advantage of the Federal Low-Income Household Water Assistance Program funds made available via the American Rescue Plan. (I&E St. 1 at 45; I&E St. 1-R at 5; I&E St. 1-SR at 53); and (3) that Aqua should be required to

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[125] The OCA noted that the Company indicated that it does not conduct any collectability studies for its water or wastewater operations assessing the rate at which the Company converts billings into collected revenue. However, the Company did state that it has collection contracts which provide contingency fees ranging between 18% to 40% of the amount collected. Thus, the OCA recommended that a 28% offset (the middle of the contingency fee range) to the gross costs of the program be applied to obtain the net program costs that the Company should be permitted to recover. OCA St. 5 at 42.

monitor available federal and state assistance programs and notify customers of all available sources of aid. (I&E St. 1 at 49; I&E St. 1-SR at 54).

b. Recommended Decision

The ALJ recommended that the Commission approve the Company's proposed USR because she found "it is clear from a review of the *Aqua-Peoples Acquisition Order* that the Commission agreed that a 'comparable' funding mechanism as those used by the natural gas and electric distribution companies in Pennsylvania is preferable." R.D. at 108. She further determined that the use of the USR, which will be subject to audit and an annual reconciliation process, will allow actual costs to be maintained and tracked separately, because the costs proposed for inclusion in the Company's USR are easily identifiable, and any adjustments to the costs would be a simple mathematical exercise. R.D. at 108.

In further support of her recommendation to use the USR reconcilable surcharge to recover Aqua's low-income program costs, the ALJ determined: (1) certain costs that the Company will incur under its CAP program are outside of its control; (2) the Company's enrollment projections, which include a substantial ramp-up in projected participation between Years 1 and 3 of the CAP,[126] could be less than or exceed the projections; (3) since there is no limit on the number of customers who could participate in the CAP, costs may vary based on enrollment levels;[127] and (4) the ability to adjust and reconcile the costs associated with such programs via the USR "is particularly important when launching a new program that may not meet or could exceed

[126] Aqua St. 10 at 11.

[127] Aqua St. 10-R at 12; see also Aqua Exhibit RFB-1-R (The OCA's witness, Mr. Colton, admitting no imitation on the number of customers who could participate was proposed).

enrollment expectations."[128] R.D. at 106-109. In view of the above, the ALJ agreed with Aqua that the reconcilable nature of the proposed USR will "ensure ratepayers are only responsible for actual program costs which may be more or less than original projections." R.D. at 109 (citing Aqua St. 10-R at 13).

The ALJ explained that if the projected low-income program costs were included in base rates, as argued by the OCA, the costs would "be subsumed regardless of the potential difference between projected and actual costs." R.D. at 109. The ALJ cited the *Final CAP Investigatory Order*[129] for the proposition that the Commission has recognized that the recovery of universal service costs through a surcharge, rather than in base rates, is a more effective way to ensure robust customer assistance programs. *Id.*

Finally, the ALJ found that the proposed rider is consistent with the general theme of the *Aqua-Peoples Settlement* to share best practices throughout Aqua and the Peoples Companies. The ALJ explained that this is reaffirmed by the plain language of the *Aqua-Peoples Settlement* which required that Aqua will include "a comparable funding mechanism that exists for electric and gas utilities in Pennsylvania." R.D. at 109 (citing *Aqua-Peoples Settlement* at ¶ 108; OCA St. 5 at 42-43). Therefore, the ALJ concluded that Aqua's proposed USR should be approved because it complies with the terms of the *Aqua-Peoples Settlement* that was approved as part of the *Aqua-Peoples Acquisition Order*. R.D. at 109.

128 Aqua St. 10-R at 13.

129 *Customer Assistance Programs: Funding Levels and Cost Recovery Mechanisms*, Docket No. M-00051923 (Final Investigatory Order entered December 18, 2006) (*Final CAP Investigatory Order*) at 15. *See also* testimony of Aqua's witness, Ms. Rita F. Black, Aqua St. 10 at 10.

c. OCA Exception No. 16 and Replies

In its Exception No. 16, the OCA excepts to the ALJ's recommendation to adopt Aqua's proposed USR to recover the costs associated with its CAPs. OCA Exc. at 26 (citing R.D. at 107-09). The OCA maintains its position that it is proper that Aqua recover the costs of the low-income programs through base rates as normal operating expenses, rather than through the reconcilable USR, and that Aqua should only be permitted to recover the *net* costs of the program. OCA Exc. at 26, 28 (citing OCA M.B. at 152-61; 175-78; OCA R.B. at 82-89).

In support of its Exception, the OCA first asserts that, contrary to the ALJ's and the Company's view, the language in the *Aqua-Peoples Settlement* that directed the Company to file "a comparable cost recovery mechanism" to the natural gas and electric utilities' cost recovery mechanism, did not require that a specific cost recovery mechanism be used. OCA Exc. at 26 (citing R.D. at 147-50). The OCA asserts that the ALJ relied on only a portion of the language in the *Aqua-Peoples Settlement*, and thus, erred by interpreting the above language to mean that Aqua *must* propose, in its next base rate proceeding, a cost-recovery mechanism *just* like that used by the natural gas and electric utilities. OCA Exc. at 26. The OCA cites to its Briefs in which it provided detailed arguments on why a reconcilable rider is not required by the *Aqua-Peoples Settlement*. OCA Exc. at 27 (citing OCA M.B. at 152-161; 175-78; OCA R.B. at 82-89).

In reply, Aqua disagrees with the OCA's position that the ALJ erred by relying on only a portion of the *Aqua-Peoples Settlement* and that the OCA is attempting to "walk back" its admission in its Briefs that Aqua was contractually obligated under this settlement to "implement a universal service program with a suite of low-income assistance programs." Aqua R. Exc. (citing Aqua R.B. at 67; OCA M.B. at 120). The Company submits that the OCA's argument is inconsistent because it wants Aqua to implement a universal service plan similar to those in place at other energy utilities, but then proposes that Aqua be required to recover its costs differently than the energy utilities' methodology. Aqua R. Exc. at 14 (citing Aqua R.B. at 68).

I&E also disagrees with the OCA's position and replies that it agrees with the ALJ's recommendation that the *Aqua-Peoples Acquisition Order* that approved the *Aqua-Peoples Settlement* permitted Aqua to use a reconcilable rider. I&E avers that Aqua's proposed USR is consistent with the directives of the Commission in the *Aqua-Peoples Acquisition Order* and Aqua's obligation to comply with the terms of the Settlement. I&E R. Exc. at 17-18.

Next, the OCA excepts to the ALJ's conclusion that the program costs are outside of the Company's control, and that a reconcilable surcharge is necessary to allow for full cost recovery and to ensure robust customer assistance programs. OCA Exc. at 27 (citing R.D. at 107-08). The OCA avers that the ALJ disregarded the fact that there is no statutory basis for the full cost recovery of water low-income program costs as there is for energy low-income program costs. Thus, the OCA asserts that a comparison between energy utilities' mature universal services programs with a statute-defined cost recovery mechanism and Aqua's proposed discount/arrearage forgiveness programs is not appropriate. OCA Exc. at 27.

Aqua replies that it disagrees with the OCA's claims that the costs of the program are within Aqua's control, and there is no statutory basis for the cost recovery of water program costs. The Company retorts that the OCA is ignoring its own admission that no enrollment limitations have been proposed, and that variance in enrollment will drive variances in costs. Aqua R. Exc. at 14 (citing Aqua M.B. at 159; OCA St. 5SR at 29).[130] In addition, the Company argues that the OCA's assertion that there is no

[130] The Company projects that the cost of discounts for the water program alone range from $3 million to $8 million. The OCA projects costs of $4 million to $10 million under its proposal. *See* Aqua R.B. at 69.

statutory basis for this reconcilable rider ignores Section 1307(a) of the Code, 66 Pa. C.S. § 1307(a). Aqua claims that it has demonstrated that the rider satisfies Section 1307(a). Aqua R. Exc. at 14 (citing Aqua M.B. at 264-265; Aqua R.B. at 68-70).

Next, the OCA argues that the ALJ ignored that every other Pennsylvania water utility with low-income discount programs, including Pennsylvania-American Water Company and Pittsburgh Water and Sewer Authority (PWSA), treat their low-income program costs as normal operating costs that are recovered through base rates.[131] OCA Exc. at 27 (citing OCA R.B. at 87; OCA St. 5SR at 28-29). The OCA asserts that the Commission should also require that Aqua continue doing the same in this case. The OCA adds that contrary to the ALJ's conclusion, there is no need for Aqua to use a reconcilable surcharge because Aqua does not anticipate that there will be substantial fluctuations in the costs of the program. OCA Exc. at 27 (OCA R.B. at 88; OCA St. 5 at 45-46).

The Company rejoins that the OCA disregards the fact that other water utilities' programs are not as robust as the programs proposed by Aqua. Aqua R. Exc. at 14 (citing Aqua M.B.at 158).

Finally, the OCA excepts to the ALJ's Recommended Decision because she did not address the OCA recommendations that only net costs, rather than gross costs, of low-income programs should be recovered, and those costs should be included in base rates, including a cost offset to reflect the benefits of the program to Aqua's uncollectible expenses. OCA Exc. at 28 (citing OCA St. 5 at 42). The OCA submits that the ALJ appeared to ignore the need for an offset which the OCA recommended be established to address the impact of the program on Aqua's uncollectible expenses. *Id.* According to the OCA, an offset is needed for the discount and arrearage forgiveness program costs in

[131] *See* OCA R.B. at 87; OCA St. 5SR at 28-29.

order to prevent the double-recovery of costs. *Id.* The OCA cites to its Briefs in which it explained that the Commission previously has concluded that double recovery is possible through a reconcilable surcharge and that an offset is appropriate here. OCA Exc. at 28 (citing OCA M.B. at 153-54; OCA R.B. at 83-85).

The Company replies that it disagrees with the OCA's claims that an offsetting reduction to Aqua's uncollectibles expense associated with the proposed USP is required. The Company asserts that the OCA's Exception should be denied because this recommendation is premature and unnecessary where a reconcilable rider is used. Aqua R. Exc. at 14-15 (citing Aqua M.B. at 155-61, 264-65; Aqua R.B. at 67-71, 107).

I&E also replies that it disagrees with the OCA's arguments in its Exceptions that Aqua's net costs of the program should be recovered in base rates. I&E R. Exc. at 12. I&E further states that it supports the ALJ's determination that the *Aqua-Peoples Settlement* requires that Aqua's proposal include "a comparable funding mechanism that exists for electric and gas utilities in Pennsylvania," which do not net their costs. I&E R. Exc. at 12 (citing R.D. at 109).

d. Disposition

The primary argument in this matter focuses on whether the *Aqua-Peoples Acquisition Order,* through the approved, modified, *Aqua-Peoples Settlement,* requires or permits Aqua to implement a reconcilable rider (*i.e.*, the proposed USR) to recover its low-income program costs in its CAP program. The ALJ, Aqua, and I&E share the opinion that it does. However, the OCA asserts in its Exceptions that the ALJ erred in her reliance on the *Aqua-Peoples Settlement* by incorrectly interpreting that it meant that Aqua was given the clearance to file the reconcilable USR exactly like those used by its Peoples' affiliates to recover the costs associated with its low-income CAP.

Upon our review of the *Aqua-Peoples Merger Order* and the *Aqua-Peoples Settlement*, we disagree with the ALJ's reliance on language in the *Aqua-Peoples Settlement* that the ALJ used as the basis to recommend that the Company's proposed USR be approved. As the OCA noted, the ALJ relied on the testimony of Aqua's witness, Ms. Rita Black, who testified with regard to the Company's implementation of the terms of Paragraph 108 of the *Aqua-Peoples Settlement* as follows:

> [Paragraph 108] notes that, through the Helping Hand Collaborative process, Aqua PA was to consider development of a comprehensive and universal service and conservation program. The items for evaluation included a customer assistance program, hardship fund, water conservation program, low-income service repair program and a comparable funding mechanism as utilized by energy utilities in the Commonwealth. Following this evaluation, Aqua PA would propose a recoverable universal service plan in its next base rate proceeding using input from the Helping Hand Collaborative and best practices from the Peoples Companies.

Aqua St. 10 at 3; *see also Merger Settlement* at 135; OCA M.B. at 117; OCA R.B. at 85-86; OCA St. 5 at 7. In support of her recommendation, the ALJ averred, "[i]t is clear from a review of the *Aqua Peoples Acquisition Order* that the Commission agreed that a 'comparable' funding mechanism as those used by the natural gas and electric distribution companies in Pennsylvania is preferable." R.D. at 107-08 (citing *Aqua-Peoples Acquisition Order* at 147-150).

We disagree. We find that the *Aqua-Peoples Settlement* did not dictate that a specific cost recovery be used. When we adopted the *Aqua-Peoples Settlement,* we never *directed* that Aqua use the same mechanism used by the Peoples' Companies and other energy Companies to recover the costs of its low-income programs. Paragraph 108 of the *Aqua-Peoples Settlement*, which we approved without modification, is stated in its entirety as follows:

> Aqua PA will include in the Helping Hand collaborative agreed to in its recent rate case settlement at Docket No. R-2018-3003558, discussion of the development of a comprehensive universal service and conservation program that will be proposed by Aqua PA. The items to be evaluated for inclusion in Aqua PA's proposal include: (1) a bill payment/customer assistance program; (2) a hardship fund; (3) a water conservation program; (4) a low-income service repair line and replacement program; and (5) *a comparable funding mechanism that exists for electric and gas utilities in Pennsylvania.* Aqua PA will submit *a rate recoverable universal service proposal* in Aqua PA's next base rate case that considers the best practices learned from the Peoples Companies and through conversations from the Helping Hand collaborative.

Aqua-Peoples Settlement ¶ 108 at 23 (emphasis added). We note that Item No. 5 in Paragraph 108 merely states that the Company will include "a *comparable* funding mechanism" for evaluation, and the sentence following Item No. 5 states that Aqua will submit a "*rate recoverable universal service proposal*" in its next base rate case. However, the testimony of Aqua's witness, Ms. Black, quoted above, left out the word "rate" before "recoverable" when she stated, "Aqua PA would propose a *recoverable* universal service plan in its next base rate proceeding." Nothing in Paragraph 108 specifically directed the type of a comparable funding mechanism that must be evaluated. The Settlement stated only that Aqua was allowed to "consider" such a funding mechanism. Furthermore, the text "rate recoverable" implies that the costs of the universal service proposal should be recovered through base rates. In this regard we, agree with the OCA's assertion that "[i]f the parties had intended to mandate use of a funding mechanism akin to the mechanisms used by Pennsylvania's energy utilities, the Settlement would have said so."[132] Similarly, if it were the intent of the Commission to permit the use of a reconcilable rider, we specifically would have modified Paragraph 108 to state that was our intention. Accordingly, we conclude in view of the fact that the

[132] OCA St. 5SR at 36

settlement stated only that Aqua was allowed to "consider" such a funding mechanism, we reject the ALJ's reliance on Paragraph 108 in support of her recommendation that the Company's USR should be approved because it is consistent with the Commission's directive to file a reconcilable rider to recover its low-income CAP expenses.

It is also important to note that the use of a Section 1307(a) reconcilable rider, such as is proposed here, is the exception, rather than the rule, as can be observed during the history of the Commission, how few times the use of this mechanism has been either legislatively mandated (*i.e.*, when the Energy Competition Acts specifically permitted its use for energy companies) or directed by the Commission (*i.e.*, the implementation of the STAS).[133] In this regard we agree with the OCA that Section 1307(a) of the Code does not authorize the Commission to approve surcharges other than in limited circumstances.[134] OCA M.B. at 157. We further note that when we established the reconcilable surcharge recovery mechanism for energy companies pursuant to the Energy Competition Acts, we concluded that, consistent with the direction given in the Energy Competition Acts, we must allow recovery through a surcharge that is either reconciled or adjusted frequently to track changes in the level of CAP costs. *See* OCA St. 5 at 44 (citing *Final CAP Investigatory Order* at 14-15). However, those energy riders that were approved under legislative mandate for the Peoples Companies and other energy companies are not appropriate models upon which to base the cost recovery for

[133] *See* 52 Pa. Code § 69.52, Exh. A (State Tax Adjustment Surcharge Order, entered March 10, 1970). Furthermore, as I&E's witness, Mr. Sakaya, testified, "the PGC [Purchased Gas Cost], STAS and DSIC mechanisms are authorized by statute while the PWA [Purchased Water Adjustment] and ECA [Energy Cost Adjustment] are not, and, furthermore, the establishment of the PGC and STAS were specifically related to historic volatility." I&E St. 3-SR at 12-13.

[134] *See* 66 Pa. C.S. § 1307(a); *CSIC Order*, 869 A.2d at 1160; *see also Pennsylvania Indus. Energy Coal. v. Pa. PUC,* 653 A.2d 1336, 1349 (Pa. Cmwlth. 1995), *aff'd per curiam*, 543 Pa. 307, 670 A.2d 1152 (1996) (*PIEC*). The general rule for expense items is that if the item in question is normally considered in a base rate case, then singling that item out for recovery outside of a base rate case is not appropriate. *CSIC Order*, 869 A.2d at 1157; *PIEC* at 1350.

Aqua's low-income water programs because there has been no legislative carve-out for water companies such as that which exists for energy companies.

We also agree with the OCA's Exceptions in which it argues that a reconcilable rider is not needed here because the Company admitted there will not be substantial fluctuation in its low-income program costs due to changes in bills. OCA St. 5 at 45 (citing OCA-V-29). Aqua disagrees with the OCA's Exception and maintains that the OCA ignores its own witness's admission that no enrollment limitations have been proposed, and that variance in enrollment will drive variances in costs. Aqua R. Exc. at 14 (citing Aqua M.B. at 159). The Company asserts that it has projected that the cost of discounts for the water program alone will range from $3 million to $8 million, while the OCA has projected costs of $4 million to $10 million under its proposal. Aqua R. Exc. at 14 (citing Aqua R.B. at 69). Nevertheless, the OCA avers that unlike natural gas bills, which may vary widely, Aqua's water bills will not experience substantial cost fluctuations due to changes in bills. OCA St. 5 at 45. The OCA explained that the variability in costs, such as those found in energy CAPs, would not be present in Aqua's program because, except for a small portion attributable to discounts on Tier 2 consumption for the lowest income, the vast bulk of discounts provided – whether using Aqua's or the OCA's proposed discounts - are applicable only to the base facility charge and to the first tier of consumption (*i.e.*, the first 2,000 gallons of use). *Id.*

We find the OCA's arguments to be more persuasive. The variability arguments presented by the Company assumes that its and the OCA's projections will vary between $3 million to $8 million or between $4 million and $10 million from month to month. We are of the opinion that such an occurrence is unlikely because the costs associated with Aqua's low-income water assistance offerings will likely start at some point between those ranges and gradually increase over time as participation in the program increases until it eventually levels off at the top of the projected ranges, taking into account the amount of public outreach conducted by the utility and the number of customers who will actually qualify for each offering pursuant to the design of the programs. Notwithstanding the Company's and the OCA's arguments, we note that this is just one consideration to take into account in considering the reasonableness of a reconcilable surcharge; another issue is the appropriateness of implementing a reconcilable rider in this rate case proceeding rather than addressing it pursuant to Section 1307(a) in the context of a generic investigation proceeding where all water utilities would have the opportunity to participate. This is especially relevant here because, as the OCA noted, all Pennsylvania water utilities that offer discount programs, including Pennsylvania-American Water Company and PWSA, currently recover their low-income assistance program costs through base rates. OCA Exc. at 27 (citing OCA R.B. at 87; OCA St. 5SR at 28-29).

The OCA also excepted to the ALJ's adoption of the Company's position that the reconcilable USR should be approved because the program costs are outside of the Company's control and that a reconcilable surcharge is necessary to allow for full cost recovery and to ensure robust customer assistance programs. OCA Exc. at 27 (citing R.D. at 107-08). As noted, the OCA asserts in its Exceptions that the ALJ disregarded that the statutory mandate, which was enacted to permit energy companies to recover their full low-income program costs, does not apply to water utilities. The OCA further contends in its Exceptions that it is not appropriate to compare the energy utilities' mature universal services programs with a statute-defined cost recovery mechanism and Aqua's proposed discount/arrearage forgiveness programs. Aqua Exc. at 27. Aqua disagrees with the OCA's claims that the costs of the program are within Aqua's control because the OCA ignores its own admission that no enrollment limitations have been proposed, and that variance in enrollment will drive variances in costs. Aqua R. Exc. at 14 (citing Aqua M.B. at 159; OCA St. 5SR at 29). The Company also submits that, contrary to the OCA's assertion, Section 1307(a) provides a statutory basis for its proposed reconcilable rider.

Although the Company is correct that Section 1307(a) provides the statutory basis for the use of reconcilable riders, the fact remains that unlike energy companies, the water companies are not statutorily-mandated to implement universal service plans or to use a Section 1307(a) rider to recover the associated costs as are the energy companies.[135] In addition, as we stated, *supra*, use of such riders are the exception rather than the rule, and it is our preference that it is best to consider the development of a policy regarding the use of a Section 1307(a) reconcilable rider to recover water utilities' low-income programs in a generic investigation proceeding. Furthermore, we disagree with the Company that its program costs are beyond its controls; the Company is responsible for establishing the budget and parameters associated with each of its programs. In this regard, the Company has some control over the number of customers who may or may not qualify.

Next, the OCA excepted to the ALJ's Recommended Decision because the ALJ did not address its witness, Mr. Roger D. Colton's, recommendation that only net costs, rather than gross costs, of low-income programs should be recovered in base rates including via a cost offset that reflects the benefits of the program to Aqua's uncollectible expenses. OCA Exc. at 28 (citing OCA St. 5 at 42); OCA M.B. at 151-52. In this regard, the OCA averred in its Main Brief that its witness, Mr. Colton, provided the following testimony why he believed a lost revenue offset to gross low-income program costs for the discount and arrearage forgiveness programs is necessary and should be adopted:

> The "basis" for my recommended lost revenue adjustment is not that Aqua PA has performed no collectability analysis. The basis for my adjustment is that, in the absence of such an adjustment, Aqua PA will recover some parts of low-income rates twice. Aqua PA's proposal to include 100% of its low-income discount through rates assumes that, in the absence of the discount, 100% of the billed revenue to discount

[135] *See* 66 Pa. C.S. § 2804(9) for electric utilities and § 2203(8) for gas utilities.

> participants would have been collected. Only given this assumption is it reasonable to say that the dollar amount of the discount needs to be replaced by separately including that discounted revenue in rates. We know, however, that Aqua PA does not collect 100% of its low-income billings in the absence of the discount.

OCA M.B. at 153 (citing OCA St. 5SR at 30-31). The OCA further submitted in its Main Brief that Mr. Colton argued that the unpaid dollars of its low-income customers are currently reflected in base rates and that Aqua is proposing "to *continue* to reflect those unpaid dollars in rates and, *in addition*, to collect 100% of its discounted revenues *again* as though all of the discounted revenue would have been collected in the absence of the discount program." OCA M.B. at 154 (citing OCA St. 5SR at 31 (emphasis in original)). Thus, the OCA recommended, that since Aqua has collection contracts which provide contingency fees between 18% to 40% of the amount collected (OCA-II-47), that an "offset in the middle of that range (28%)" should be used to reduce the cost of Aqua's bill discount program. OCA R.B. at 83 (citing OCA St. 5 at 42).

Aqua replied that the OCA's recommendation is premature and unnecessary where a reconcilable rider is used. Aqua R. Exc. at 14-15. Aqua's witness, Ms. Black, submitted that the OCA's assertions lack merit because:

> [o]ver time, as participation in the program grows and matures to a stable level, bad debt levels will adjust accordingly, reflecting appropriate levels of collectability for the Company. I would further note that because we do not have a historical study of low income billing collections and its relation to bad debt, any adjustment proposed at this stage would be premature. Use of the reconcilable rider, which limits arrearage forgiveness recovery to those cost which are

> actually incurred due to customers receiving benefits from timely payments, will align recovery with actual collections experience.

Aqua M.B. at 161 (citing Aqua St. 10-R at 14). Aqua averred in its Reply Brief that even if this offset were necessary and appropriate, the OCA's 28% offset is unreasonable and any offset established should be based on actual collections experience gained after implementation of the CAP to ensure the offset reflects the actual collection savings. Aqua R.B. at 70-71.

We agree with the Company. In our opinion, the OCA's proposed 28% offset is arbitrary; and it would not be prudent to adopt it as a realistic offset to reflect actual collections savings. Nevertheless, we agree with the OCA that there is a potential that the Company's CAP may result in a double recovery of low-income rates. Inasmuch as the Company acknowledged that any offset should be based on actual collections experienced gained after the implementation of the CAP to ensure it is an accurate representation of actual collections savings, we shall deny the OCA's Exception concerning its recommended offset and, instead, direct Aqua to take the necessary actions within its Company to monitor and maintain the necessary information that could be used in its next base rate proceeding to determine whether a double-recovery is occurring, and if so, to determine an appropriate offset that should be applied to prevent any double recovery. The Company is further directed to consult with the OCA and I&E to determine the necessary data needed to accomplish this directive.

Accordingly, consistent with the discussion above, we shall reverse the ALJ's recommendation and adopt the OCA's Exception No. 16, in part, by rejecting the Company's proposed reconcilable USR and requiring that the Company continue to recover its low-income program costs through base rates. However, the OCA's Exception No. 16, with regard to its requests that the Company be directed to collect only the net costs of its low-income program in this proceeding is denied because an appropriate offset has not been determined in this proceeding and needs further review.

Therefore, consistent with the above discussion, the Company is directed to begin monitoring and reviewing the appropriate billing data for purposes of determining, in its next base rate proceeding, if, and to what extent, any offset to its low-income program cost recovery is necessary to avoid any double recovery the Company may receive through actual collections after the implementation of its CAP. The Company is further directed to consult with the OCA and I&E to determine the necessary data needed to accomplish this directive.

XII. Miscellaneous Issues

A. Universal Service Issues

1. Consideration of Affordability and CAP Design

a. Positions of the Parties

Aqua explained that before this proceeding, it made certain commitments regarding its existing Helping Hand Program[136] and the evaluation and development of a more comprehensive USP as a part of the Commission's approval of the acquisition of the Peoples Companies by Essential Utilities, Inc., f/k/a Aqua America, Inc. Aqua M.B.

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[136] Several years ago, Aqua implemented a program called "A Helping Hand" to facilitate the payment of water and wastewater bills by its low-income residential customers. Helping Hand is "a program designed to help limited-income customers with arrearages to reduce the amount they owe through regular monthly payments." Under the program, "[f]or each timely payment made, participants receive a $25 credit towards their prior arrearage." Helping Hand does not provide a discount or Percentage of Income Payment Plan (PIP). Aqua St. 10 at 4.

at 141 (citing *Aqua-Peoples Acquisition Order*). In the settlement agreement the Commission approved in the *Aqua-Peoples Settlement*, the parties agreed as follows:

> 108. Aqua PA will include in the Helping Hand collaborative agreed to in its recent rate case settlement at Docket No. R-2018-3003558, discussion of the development of a comprehensive universal service and conservation program that will be proposed by Aqua PA. The items to be evaluated for inclusion in Aqua PA's proposal include: (1) a bill payment/customer assistance program; (2) a hardship fund; (3) a water conservation program; (4) a low income service repair line and replacement program; and (5) a comparable funding mechanism that exists for electric and gas utilities in Pennsylvania. Aqua PA will submit a rate recoverable universal service proposal in Aqua PA's next base rate case that considers the best practices learned from the Peoples Companies and through conversations from the Helping Hand collaborative.

Aqua M.B. at 141-142 (citing *Aqua-Peoples Settlement* at ¶ 108).

Consistent with its commitments in the *Aqua-Peoples Settlement*, Aqua has proposed to implement a CAP that builds upon the successful aspects of Helping Hand in order to further assist low-income customers throughout its service territory. Aqua M.B. at 143 (citing Aqua St. 10 at 5-8). The proposed CAP adds tiered bill discount benefits, similar to the structure in place at the Peoples Companies, and an Emergency Repair Program to the benefits already afforded under Helping Hand. The proposed three tiers are set at 100% of the Federal Poverty Level (FPL), 150% FPL, and 200% FPL, with the highest level of discounts provided to those in the first tier and gradually reducing the discounts in the other tiers. Aqua M.B. at 145 (citing Aqua St. 10 at 7; Aqua Exh. RFB-2 (setting forth the discounts to the Base Facility Customer Charge and Consumption Charge that an enrollee can obtain based on their income tier)).

The OCA analyzed the affordability of water and wastewater bills and cited to the extensive testimony of its witness, Mr. Colton. OCA M.B. at 120-131. CAUSE-PA similarly argued that existing rates are unaffordable. CAUSE-PA M.B. at 17-18. Therefore, both Parties recommended modifications to Aqua's proposed CAP.

Among other things, the OCA argued that the benefits of the affordability program contemplated by the proposed USP should be modified to increase the level of discounts provided to customers and to adjust the structure of the income tiers. OCA M.B. at 136-39; 141-42. The OCA also recommended that the design of the discount program should evolve toward a PIP[137] similar to the program operated by Aqua's sister utility, Peoples Gas. The OCA stated that Aqua should not immediately move to a PIP design but, rather, that a series of policy decisions by the Commission would first be needed, including what water and wastewater burden should be deemed affordable, and such decisions are best addressed in a statewide proceeding involving all water and wastewater utilities and related stakeholders and would involve additional analysis and data than is available in this rate proceeding. OCA M.B. at 135-136; OCA St. 5 at 31. The OCA proposed that Aqua be required to present a PIP in its next base rate proceeding. OCA M.B. at 144-52.

CAUSE-PA supported the OCA's recommendations regarding discount structure and adjusted income tiers. CAUSE-PA M.B. at 21 (citing OCA St. 5 at 35,

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[137] The Commission's CAP Policy Statement provides the following:

> Total payment for total electric and natural gas home energy under a percentage of income plan is determined based upon a scheduled percentage of the participant's annual gross income. The participating household's gross income and size place the household at a particular poverty level based on the [Federal Poverty Income Guidelines].

52 Pa. Code § 69.265(2)(i).

Table 9; OCA St. 5 at 39, Table 13; CAUSE-PA St. 1-R at 7). Additionally, CAUSE-PA stated that as its witness, Harry Geller, Esq., recommended in his direct testimony, Aqua should be required to closely monitor and analyze the water and wastewater burdens of CAP participants and should transition its proposed bill discount structure to a PIP structure if participants are not reaching acceptable levels of affordability. CAUSE-PA M.B. at 22 (citing CAUSE-PA St. 1 at 44-45; OCA St. 5 at 31).

Aqua explained in its direct and rebuttal testimony that it performed an affordability analysis and considered bill affordability as a part of the development of the proposed USP. Aqua M.B. at 144-48; Aqua R.B. at 58. The Company averred that the program, as designed, takes affordability into account and also balances the interests of ratepayers who are not low-income, but who bear the costs of universal service programs. Specifically, the Company contended that the OCA and CAUSE-PA fail to consider the effect of their proposed changes upon the rates of non-low-income customers. Aqua R.B. at 59. Aqua also argued that its proposed bill discount program should not be modified. Aqua M.B. at 153-54; Aqua R.B. at 60. Aqua stated that it should not be required to propose a PIP in its next base rate proceeding, particularly when the Company questions the cost/benefit of a PIP for water and wastewater customers at this time. Aqua submitted that once its proposed USP is in place, it can and should be evaluated in the context of a USP proceeding specifically focused on the effectiveness, costs, and benefits of the programs. Aqua R.B. at 63. Aqua further submitted that the OCA and CAUSE-PA's other suggestions regarding discount structure and adjusted income tiers, which would require programmatic changes to the existing system, were unreasonable and not feasible at this time, because Aqua will be converting its billing system to SAP in 2023 and development of the system is in the early stages. *Id*. at 61-62.

b. Recommended Decision

The ALJ agreed with the Company that substantial modification of Aqua's proposed CAP was not appropriate at this time. While the ALJ recognized that the Code permits consideration of a broad range of issues in base rate proceedings, the ALJ concluded that this rate case was not the best forum for considering "the complex social and economic issues related to affordability as it impacts CAP design." R.D. at 113. The ALJ noted the OCA's acknowledgment that the Commission has not established the water and wastewater burden that should be deemed affordable and the OCA's concession that the "policy decision of the appropriate water and wastewater burdens is best addressed in a statewide proceeding involving all water/wastewater utilities and related stakeholders or would involve additional analysis that would require more time and data than is available in this proceeding." *Id*. (citing OCA M.B. at 135-36; OCA St. 5 at 31).

For example, the ALJ pointed out that the OCA and CAUSE-PA proposed that Aqua should be required to implement a PIP in its next base rate case. The ALJ determined that this base rate proceeding was not an adequate venue for consideration of whether implementing a PIP is reasonable, and this complex issue would be better reviewed in the universal service stakeholder process which would allow the parties to review data from the current program and its associated costs through a more flexible discourse. The ALJ similarly found that many of the structural refinements to the CAP design regarding bill discount and arrearage forgiveness benefits should be more fully considered at a later time, reasoning that Aqua explained that many of these recommendations cannot be efficiently implemented until the Company converts its current customer information system (CIS) to SAP in 2023. R.D. at 113. The ALJ agreed with Aqua that consideration of the structural changes proposed by the OCA and CAUSE-PA should be deferred until Aqua's transition to SAP, noting that the Company has committed to providing arrearage forgiveness benefits for each full CAP payment made, regardless of timeliness, when the conversion to SAP is completed. *Id*. at 113-14 (citing Aqua St. 10-R at 10).

The ALJ further reasoned that the OCA and CAUSE-PA have not demonstrated that the costs to make these proposed changes while Aqua is using its current CIS is reasonable. The ALJ stated that such proposed enhancements can be considered during the process of evaluating the effectiveness of the design of Aqua's universal service program in the future. The ALJ noted the OCA's concession that Aqua's proposed bill discount program will improve affordability for low-income customers. R.D. at 114. The ALJ also noted that Aqua's proposed USP was presented to and vetted by stakeholders participating in its Helping Hand Collaborative, including CAUSE-PA and the OCA, before this proceeding. *Id*. (citing Aqua St. 10 at 3). The ALJ further noted that Aqua was able to draw upon the knowledge and expertise of its affiliates, the Peoples Companies, and the Peoples Companies' Director of Community Assistance Program, Ms. Black, to develop the USP. The ALJ concluded that while a robust low-income program is required to offset the rate increases proposed in this case, increasing costs to non-low-income customers should also be mitigated. R.D. at 114.

c. OCA Exception No. 17, CAUSE-PA Exception No. 1, and Replies

In its Exception No. 17, the OCA avers that the ALJ erred in her determination to adopt Aqua's proposed program design without modification. OCA Exc. at 28. The OCA argues that the ALJ disregarded the evidence it presented, including OCA witness Mr. Colton's, extensive analysis of the affordability of Aqua's proposed program design for its water and wastewater discount and arrearage forgiveness proposals. *Id*. (citing OCA M.B. at 117-75; OCA R.B. at 73-82, 91-96). The OCA states that, instead, the ALJ improperly deferred the determination of the OCA's recommended program modifications to a generic proceeding sometime in the future. OCA Exc. at 28.

In so doing, the OCA believes that the ALJ misunderstood the purpose of Mr. Colton's testimony. The OCA explains that the purpose of Mr. Colton's affordability analysis was not to create a final, definitive assistance program for Aqua but, rather, Mr. Colton understood that the program would need to evolve and recommended that the affordability targets be established in a future generic proceeding and that Aqua propose a PIP in its next base rate proceeding. *Id*. at 29. The OCA emphasizes that Mr. Colton's testimony was intended to demonstrate the problems with Aqua's proposed discount and arrearage forgiveness levels, particularly for customers from 0-50% of the FPL and to show that the proposed program design will not achieve the objectives of the *Aqua-Peoples Settlement* to consider a "comprehensive universal services program." *Id*. (citing *Aqua-Peoples Settlement* at 135; OCA M.B. at 133-36; OCA R.B. at 76-77).

The OCA explains that a comprehensive universal services program should be designed to achieve affordability for customers, and the evidence Mr. Colton presented demonstrated that the discount program Aqua proposed for water and wastewater customers will significantly under-serve those customers from 0-50% of the FPL and will not help customers achieve affordability after implementation. *Id*. The OCA additionally states that the ALJ ignored the evidence of the shortcomings of the continuation of the current $25/month arrearage forgiveness program described in Mr. Colton's testimony. OCA Exc. at 29 (citing OCA St. 5 at 59-60, Schs. RDC-1, RDC-2; OCA St. 5-SR at 7-8). As such, the OCA argues that the Commission should approve the OCA's proposed design modifications to Aqua's water and wastewater discount and arrearage forgiveness programs. OCA Exc. at 29 (citing OCA M.B. at 117-75; OCA R.B. at 73-82, 91-96).

In its Exception No. 1, CAUSE-PA avers that the ALJ erred as a matter of law and sound public policy by concluding that issues involving the design of Aqua's rate discount and arrearage forgiveness programs are not properly considered in the context of this rate proceeding. First, CAUSE-PA argues that an evaluation of the justness and reasonableness of any proposed rate increase must necessarily analyze the effect of the rate increase on the ability of residential consumers to afford service and, consequently, the adequacy and design of rate assistance programming. CAUSE-PA Exc. at 4. CAUSE-PA states that the rules, regulations, and practices for Aqua's universal service programs affect the charges to both program participants and non-participants, and, therefore, they fit squarely within the definition of rates that must be just and reasonable and must be evaluated in this rate proceeding. *Id*. at 5 (citing *Pa. PUC v. PGW*, Docket No. R-2020-3017206 (Order on PGW's Motion *in Limine* dated July 8, 2020) at 3). CAUSE-PA notes the testimony of Mr. Geller, who explained that it is not appropriate "to raise rates for water and wastewater service without first ensuring that low and moderate income customers are able to receive affordable service under just and reasonable terms." CAUSE-PA Exc. at 5 (citing CAUSE-PA St. 1 at 10). CAUSE-PA asserts that universal accessibility is a polestar principle of ratemaking for essential, life-sustaining services like water and wastewater. CAUSE-PA Exc. at 5-6.

CAUSE-PA submits that low-income customers represent a significant portion of Aqua's residential customers, as Aqua estimates that nearly one in four households in its service territory have income below 200% of the FPL and has identified approximately 5% of its total residential customers as low-income. CAUSE-PA argues that in order to meaningfully conduct an investigation of proposed and existing rates, it is necessary to examine the lawfulness, justness, and reasonableness of rates for all consumers, including low-income consumers, and such an investigation necessarily includes an examination of the design and delivery of Aqua's universal service programs. CAUSE-PA Exc. at 6.

CAUSE-PA notes the concerns it has raised throughout the proceeding related to rate affordability for low-income customers and the inadequacy of Aqua's proposed CAP to ensure reasonable rate affordability for low-income CAP participants.

CAUSE-PA also notes that based on these concerns, it recommended that Aqua be required to: (1) implement the improved discount levels and adjusted income tiers recommended by the OCA expert witness, Mr. Colton, and supported by Mr. Geller; (2) closely monitor and analyze water/wastewater burdens of CAP participants; and (3) transition to a PIP structure if participants are not reaching acceptable levels of affordability. *Id*. at 7. CAUSE-PA further notes the testimony and evidence its witness presented that Aqua's Helping Hand arrearage forgiveness program is inadequate to address high levels of arrears accrued by low-income customers and further exacerbates rate unaffordability faced by these customers. *Id*. at 7-8. CAUSE-PA states that it has recommended that Aqua should be required to revise the structure of Helping Hand so that: (1) when entering the program, pre-program arrears are frozen and no longer accrue late fees or charges; and (2) for each in-full payment that a customer makes while enrolled in Helping Hand, 1/36th of the customer's frozen arrears, or $25, whichever is greater, should be forgiven. *Id*. at 8.

CAUSE-PA avers that by precluding meaningful consideration of universal service issues in the context of this rate proceeding, the ALJ has disregarded the statutory mandate to ensure that all rates are just and reasonable and contradicted past precedent considering universal service issues. CAUSE-PA requests that the Commission clarify that examination of the structure and affordability of universal service programs is properly addressed in the context of this rate case. CAUSE-PA Exc. at 9-10.

Second, CAUSE-PA argues that the informal universal service stakeholder process is not a substitute for consideration of the impact a rate increase will have on low-income customers in this rate proceeding and the need to make corresponding adjustments to the rates charged through universal service programming. CAUSE-PA supports using universal service stakeholder meetings to provide a forum for parties and stakeholders to discuss issues surrounding the design and delivery of universal service programming and to reach consensus where possible. CAUSE-PA Exc. at 11.

Nevertheless, CAUSE-PA avers that informal stakeholder meetings are not an adequate substitute for a formal examination of rates produced by universal service programming in the context of a rate proceeding, because CAUSE-PA believes that informal stakeholder processes lack the tools necessary to meaningfully investigate universal services, including the use of discovery and evidentiary hearings. *Id*. at 11-12. CAUSE-PA submits that informal processes do not provide for a mechanism to require Aqua to implement, or even consider, parties' proposals and if Aqua fails to implement recommended improvements, parties would not have a clear path to take exception to or appeal Aqua's decisions. *Id*. at 12.

Third, CAUSE-PA argues that the continued need to address water and wastewater affordability on a statewide level does not preclude review of the adequacy of Aqua's low-income programs in the context of this rate proceeding. CAUSE-PA states that all rates must be just and reasonable and that the absence of a statewide affordability standard does not eliminate this requirement. CAUSE-PA Exc. at 12. CAUSE-PA supports the initiation of a statewide proceeding to establish formal Commission policy on water and wastewater affordability and applicable standards and guidelines to help ensure that all Pennsylvanians can afford water and wastewater services. *Id*. at 12-13. However, CAUSE-PA asserts that the absence of formal, statewide policy does not bar consideration of program improvements critical to ensuring low-income customers can reasonably afford to connect to and maintain water and wastewater services in the context of this or other rate proceedings. CAUSE-PA takes issue with the ALJ reaching a conclusion on several aspects of Aqua's universal service programming, such as the verification process and other program rules, while declining to reach conclusions about the overall design and benefits provided through the program. *Id*. at 13.

In its Replies to Exceptions, Aqua avers that both the OCA and CAUSE-PA's Exceptions regarding its proposed USP lack merit. Aqua R. Exc. at 15. Aqua states that the ALJ properly recognized that the Company's proposed USP will improve affordability and benefit customers, while also balancing the implementation of this new program as a part of this base rate case with the fact that Aqua will convert its existing customer information system (CIS) to SAP in 2023. *Id*. (citing R.D. at 113-14). Aqua submits that it demonstrated that the additional income tiers, changes to benefits, and other proposed modifications that the OCA and CAUSE-PA propose are incompatible with the Company's existing CIS and would increase the costs of implementing the USP. Aqua R. Exc. at 15-16 (citing Aqua M.B. at 148-155; Aqua R.B. at 56-67).

Aqua continues that CAUSE-PA's claims regarding the use of the informal stakeholder process misread the Recommended Decision, as the ALJ did not "relegate" the evaluation of the impacts of base rate increases to the informal stakeholder process. Aqua states that, rather, the ALJ recognized that in the context of this base rate case, the informal stakeholder process could be used to further present and discuss possible modifications to the program before Aqua's next base rate case, or another case involving modifications to the USP, is initiated. Aqua R. Exc. at 16. Aqua also states that CAUSE-PA's claim that addressing affordability concerns in a statewide proceeding should not preclude an evaluation of low-income impacts and that the USP in this base rate case misses the point, because the ALJ properly found that an "affordability" determination should be made at the statewide level since it will involve all water and wastewater utilities. *Id*. (citing R.D. at 113).

d. Disposition

Upon review, we agree with the ALJ that certain modifications and determinations regarding Aqua's proposed CAP are not appropriately considered in the context of this base rate proceeding. For instance, we do not have sufficient information in this proceeding to require Aqua to propose a PIP in its next base rate proceeding, as the OCA proposes. It is unclear at this time what the cost, benefits, and overall effectiveness of such a program would be for a water/wastewater public utility. As the ALJ stated, this complex issue would be better reviewed in a universal service stakeholder process that would allow the parties to review data from the current program and its associated costs through a more flexible discussion. The OCA itself acknowledged that before Aqua could move to a PIP design, a series of policy decisions by the Commission would first be needed, including what water and wastewater burden should be deemed affordable, and such decisions are best addressed in a statewide proceeding involving all water and wastewater utilities and related stakeholders and would involve additional analysis and data than is available in this rate proceeding. OCA M.B. at 135-36; OCA St. 5 at 31.[138]

Similarly, we agree with the ALJ that the structural changes the OCA and CAUSE-PA proposed to the CAP design regarding bill discount and arrearage forgiveness benefits should be more fully considered at a later time, particularly because Aqua explained that many of these recommendations cannot be efficiently implemented until the Company converts its current CIS to SAP in 2023. *See* R.D. at 113. Aqua has presented evidence in this proceeding to demonstrate that its proposed CAP, which includes its Helping Hand arrearage forgiveness program and tiered bill discount benefits similar to the structure in place at the Peoples Companies, is reasonable. Aqua explained in its testimony that it performed an affordability analysis and considered bill affordability as part of the development of its proposed USP. Aqua St. 10 at 6-7.

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[138] The Commission engaged in a holistic review of universal service and energy conservation programs of electric distribution companies (EDCs) and natural gas distribution companies (NGDCs), including a thorough examination of the effects of the Commission's current energy burden thresholds, focusing on whether existing CAP pricing was affordable for low-income customers. The Commission's review and examination resulted in the adoption of CAP policy changes and amendments to the Commission's existing CAP Policy Statement at 52 Pa. Code § 69.261–69.267. *See Amendments to Policy Statement on Customer Assistance Program, Final Policy Statement Order*, Docket No. M-2019-3012599 (Order entered November 5, 2019). The Commission has not engaged in a similar review and examination concerning water and wastewater public utilities operating in Pennsylvania.

Ms. Black testified that consistent with the Aqua-Peoples Settlement, Aqua's proposed USP was presented to and vetted by stakeholders participating in its Helping Hand Collaborative, including CAUSE-PA and the OCA, before this proceeding. The Collaborative discussed aspects of the Company's proposal, including needs analysis, projected enrollment levels, proposed discounts, program designs, and estimated costs, and the participants noted the tiered benefits were an important part of the design by providing the highest amount of benefits to the most vulnerable. Ms. Black noted that the group did not recommend any changes to the proposal at that time. Aqua St. 10 at 13.

Ms. Black further testified that the OCA and CAUSE-PA's suggestions regarding discount structure and adjusted income tiers would require programmatic changes to the existing system, which currently maintains the Company's customer data. Ms. Black explained that changes to the existing system are not recommended, as Aqua will be converting its billing system to SAP in 2023, and development of the system is in the early stages. Aqua St. 10-R at 8. Ms. Black stated that Aqua's proposed CAP is intended to improve affordability while maintaining reasonable program costs for other ratepayers from whom discounts are recovered. Ms. Black testified that the Company's proposal decreases low-income customers' monthly bill responsibilities by offering discounts that are tiered to provide larger discounts to those with lower income. *Id*. at 10.

As proposed, we conclude that Aqua's program is reasonable under the circumstances as it takes affordability into account and balances the interests of low-income customers as well as the interests of ratepayers who are not low-income but bear the costs of universal service programs. Based on the record, we agree with the ALJ that the OCA and CAUSE-PA have not demonstrated that the costs to make their proposed changes while Aqua is using its current CIS are reasonable and that any such proposed enhancements can be considered during the process of evaluating the effectiveness of the design of Aqua's universal service program in the future.

Our decision on this issue is consistent with prior decisions in which we have determined that it was not appropriate to consider proposals relating to a public utility's energy burdens, CAP, and other universal service program issues within the context of a base rate proceeding, finding that such proposals are more properly considered in a public utility's Universal Service and Energy Conservation Plan (USECP) proceeding. *See PECO Gas* at 195; *Columbia Gas* at 160. While water and wastewater public utilities are not required to file USECPs with the Commission, any possible modifications to Aqua's universal service programs, including a move toward a PIP, can be discussed as part of Aqua's Helping Hand Collaborative or a larger, statewide stakeholder proceeding and presented to the Commission in a future proceeding appropriate for addressing Aqua's universal service programs, whether it be Aqua's next base rate case or another proceeding involving modifications to the Company's USP. For these reasons, we deny OCA Exception No. 17 and CAUSE-PA Exception No. 1.

2. Income Verification

a. Positions of the Parties

I&E generally agreed with the Company's proposed USP. However, I&E's witness, Ms. Wilson, recommended that the Company be required to verify enrollees' income for CAP eligibility to ensure the legitimacy of applicants and prevent misuse or abuse of the program. I&E M.B. at 60-62 (citing I&E St. 1 at 45-47).

Aqua currently allows participants to self-attest to their income. Aqua explained that discount water programs "do not typically require income documentation for participation" and that "[p]roviding income documentation can be a barrier to enrollment for eligible households." Aqua stated that the Commission has previously encouraged self-attestation of income. Aqua noted that its witness, Ms. Black testified that during the periods where self-attestation was used, Peoples Companies "did not see a spike in enrollment levels as a result of this flexibility and participation levels, year over year, are relatively flat." Aqua also noted Ms. Black's testimony that as with any income-based programs, there may be individuals that attempt to perpetrate fraud, but customers who are genuinely low-income customers are generally those that seek assistance. Aqua M.B. at 150 (citing Aqua St. 10-R at 3-4).

The OCA agreed that the Company should be permitted to use self-attestation of income and that income verification should not be required for participation in the program. The OCA recommended, however, that the Company review the income qualifications for randomly selected CAP participants and report error rates to the Commission's Bureau of Consumer Services (BCS). The OCA stated that to the extent error rates are not reasonable, BCS and Aqua should develop appropriate remedial action. OCA M.B. at 144.

Similarly, CAUSE-PA opposed the imposition of stringent income documentation requirements for Aqua's universal service programs, including its proposed CAP. CAUSE-PA argued that I&E did not present any evidence to support its contention that such income documentation would prevent fraud or that fraud was occurring in the first instance. CAUSE-PA also argued that restrictive income documentation requirements would be a barrier to low-income customers successfully enrolling in CAP and hinder the success of the proposed CAP at its outset. CAUSE-PA R.B. at 18. CAUSE-PA further argued that I&E's proposal lacked critical details for how income documents will be collected and evaluated, what income documents will be accepted, and how applicants will be informed if the documentation submitted is not received or is deemed unacceptable. *Id*. at 19.

b. Recommended Decision

The ALJ agreed with Aqua that I&E's recommendation regarding income verification should be rejected. The ALJ reasoned that based on Ms. Black's experience, the benefit of removing a barrier to low-income customers outweighs the risk of abuse or harm to paying customers. R.D. at 115.

c. I&E Exception No. 3 and Replies

In its Exception No. 3, I&E argues that the ALJ erred in rejecting I&E's recommended income verification proposal for CAP eligibility. I&E avers that the ALJ erroneously accepted Aqua's position that the benefit of removing a barrier to low-income customers outweighs the risk of harm to paying customers. I&E Exc. at 6. I&E points out that when asked about Peoples' CAP during discovery, Aqua stated that "Peoples' CAP requires income documentation from an interested customer to certify income eligibility for participation" and upon recertification. *Id*. (citing I&E St. 1 at 46). I&E also points out that the ALJ acknowledged its concern that as with other income-based programs, there may be individuals who attempt to perpetrate fraud. I&E Exc. at 6 (citing R.D. at 115).

I&E contends that the Commission should accept its recommendation regarding income verification for CAP eligibility. I&E Exc. at 7. I&E states that it explained that the program Aqua proposed will be a full-scale USP funded by ratepayers. I&E also notes that it argued that the program as proposed is based on a specific level of benefits matched to a specific percentage of the FPL and, as such, logic dictates that incomes must be verified to properly administer and award the graduated program benefits. *Id*. (citing I&E M.B. at 62). I&E believes that if the Company does not perform income verifications, this would subject the USP to potential abuse that would harm responsible customers that pay their bills. I&E Exc. at 7. I&E further argues that support for income verification is set forth in the Code and the Commission's Regulations and that in enacting Chapter 14 of the Code, 66 Pa. C.S. §§ 1401-1419, the Pennsylvania General Assembly intended to protect responsible bill paying customers from rate increases attributable to other customers' delinquencies. I&E Exc. at 7 (citing I&E M.B. at 62). I&E avers that any abuse of the CAP programs through income self-attestation by ineligible customers would have the same negative affect on the responsible, paying customers and may also harm eligible customers. I&E Exc. at 7. Moreover, I&E points out that as stated in Aqua's rejoinder testimony, Aqua's provider of administrative services, Dollar Energy Fund, already has the cost of income verification built into its proposal. *Id*. (citing I&E M.B. at 62).

In its Replies to Exceptions, Aqua avers that the ALJ correctly rejected I&E's recommendation that CAP enrollees be required to verify their income. Aqua states that its proposal is based on experience showing that income documentation can be a barrier to enrollment. Aqua R. Exc. at 17. Aqua notes that this concern must be balanced against the risk of fraud; however, Aqua stresses that when Peoples used self-attestation, it did not experience a rise in enrollment levels that was indicative of a serious effort to defraud the program. *Id*. (citing Aqua M.B. at 150). Aqua submits that the CAP is a new program for its low-income customers, and barriers to participation should be avoided when possible. Aqua R. Exc. at 18 (citing Aqua M.B. at 150; Aqua R.B. at 62).

In its Replies to Exceptions, the OCA avers that the ALJ correctly denied I&E's income verification proposal. OCA R. Exc. at 23. The OCA's position is that Aqua should be permitted to use self-attestation of income for its program. *Id*. (citing OCA M.B. at 143-144). In response to I&E's reliance on Chapter 14 in support of its proposal, the OCA states that Chapter 14 does not specifically address income verification for any CAP. The OCA also argues that the evidence does not support the idea that abuse or fraud will occur without income verification but, instead, supports the opposite conclusion. OCA R. Exc. at 23. The OCA explains that water companies do not typically require income documentation for participation and requiring income documentation can be a barrier to enrollment. *Id*. (citing R.D. at 115; Aqua St. 10-R at 4). The OCA notes that the Commission has also previously supported the use of self-attestation of income. OCA R. Exc. at 23. The OCA further notes that during the pandemic, Peoples allowed customers to enroll using self-attestation of income and did not see a spike in enrollment levels. *Id*. (citing Aqua St. 10-R at 4; OCA R.B. at 80).

In its Replies to Exceptions, CAUSE-PA states that the ALJ properly found that I&E's recommendation to impose additional income verification requirements should be rejected. CAUSE-PA R. Exc. at 3. CAUSE-PA avers that Aqua is, in fact, proposing a verification process for its CAP, which the ALJ approved, as Aqua proposes to use self-declared income to verify CAP eligibility and for recertification purposes. CAUSE-PA points out that Aqua is not, however, proposing to require applicants to submit physical documentation of income because such a requirement would pose burdensome obstacles for low-income customers most in need of assistance. *Id*. at 4 (citing CAUSE-PA R.B. at 17-18).

CAUSE-PA additionally contends that I&E has not presented any evidence to support its contention that failure to impose income documentation requirements will cause universal service application processes to be abused and will ultimately harm other ratepayers and residential customers. CAUSE-PA R. Exc. at 5 (citing CAUSE-PA R.B. at 18). CAUSE-PA states that its witness, Mr. Geller, testified that imposing more restrictive income documentation requirements, as I&E recommends, will act as a barrier to low-income customers successfully enrolling in universal service programs and hinder the success of the proposed CAP. CAUSE-PA R. Exc. at 5 (citing CAUSE-PA R.B. at 18-19). CAUSE-PA submits that Aqua's low-income programs have historically had low enrollment levels, particularly when measured against the number of low-income customers Aqua estimates are eligible for assistance. *Id*.

CAUSE-PA also opposes I&E's proposal to require Aqua to implement income documentation requirements for households to recertify enrollment in Aqua's universal service programs. As discussed in CAUSE-PA's Reply Brief, Mr. Geller extensively described how periodic recertification requirements pose difficulties for vulnerable low-income customers, including seniors or individuals with disabilities, because these households more often lack access to transportation and struggle to gather and submit formal income documentation. CAUSE-PA continues that these vulnerable households are also more likely to rely on fixed income sources that tend not to change from year to year, making recertification requirements unnecessary and administratively burdensome. As Mr. Geller noted, available independent evaluations of USECPs of other regulated Pennsylvania utilities have shown that requiring submission of income documentation through program recertification is a significant cause of high program attrition. CAUSE-PA R. Exc. at 7 (citing CAUSE-PA R.B. at 19).

Further, CAUSE-PA argues that I&E's reliance on Chapter 14 to support its income documentation proposal is misplaced because I&E fails to recognize that Chapter 14's declaration of policy expressly recognizes that Chapter 14 was enacted to improve payments for those "*capable of paying*," rather than to unfairly penalize those who cannot afford services. CAUSE-PA R. Exc. at 8 (citing 66 Pa. C.S. § 1402(2)). CAUSE-PA asserts that ensuring robust access to Aqua's universal service programs is consistent with the intent of Chapter 14 to provide greater equity among all customers. CAUSE-PA R. Exc. at 8.

Moreover, CAUSE-PA is concerned that I&E's proposal continues to lack critical details for how income documents will be collected, what income documents will be accepted, how income documents will be evaluated, and how applicants will be informed if their submitted documentation is not received or is considered unacceptable. CAUSE-PA believes that failing to provide these details has the potential to lead to widespread ambiguities in program requirements that will further impede low-income customers from successfully enrolling in Aqua's universal service programs. Accordingly, CAUSE-PA supports the income verification process Aqua proposes and opposes I&E's recommendations to impose additional income documentation requirements. *Id*. Nevertheless, CAUSE-PA states that if the Commission decides to require additional income verification for Aqua's universal service programs, including the proposed CAP, such process should be implemented on a pilot basis to allow Aqua, the Parties and stakeholders, and the Commission to monitor how CAP enrollment, retention, and costs are impacted and to determine if there is any evidence of abuse of the universal service process. *Id*. at 8-9.

d. Disposition

Upon review, we conclude that Aqua should require income documentation from an interested customer to certify income eligibility for participation in its CAP and upon recertification in a manner similar to that of the Peoples Companies.[139] I&E's witness, Ms. Wilson, testified that while the Helping Hand program has historically been funded through voluntary donations and shareholder contributions, Aqua's proposed program would be funded through the proposed Universal Service Rider and would be fully ratepayer funded. I&E St. 1 at 44; I&E Exh. 1, Sch. 8.[140] While as some of the Parties note, this Commission took some steps in response to the COVID-19 pandemic to reduce barriers to participation, such as encouraging self-attestation of income for enrollment and encouraging utilities to halt the process of removing customers for failure to recertify income (*see, e.g*., Aqua St. 10-R at 4), we are not otherwise aware that this Commission has approved a ratepayer-funded low-income program that does not include

[139] *See* Peoples Natural Gas Company LLC Universal Service and Energy Conservation Plan 2015-2018, Docket No. M-2014-2432515, at 8-10.

[140] As set forth in XI.E.3, *supra*, we are rejecting the Company's proposed reconcilable USR and requiring that the Company continue to recover its low-income program costs through base rates.

some form of documented income-verification. EDC and NGDC's CAPs require participating households to document their income eligibility periodically. Given the size and nature of Aqua's proposed program, which is larger and more robust than most of the other water utilities' programs, it makes sense to implement income eligibility processes similar to those of the EDCs and NGDCs.

We addressed a similar issue in reviewing National Fuel Gas Distribution Corporation's (NFG) 2017-2020 USECP.[141] During that proceeding, NFG disclosed that it did not require its CAP participants to reverify income eligibility after enrollment, and that during recertification, NFG was accepting the household's verbal declaration of income. *NFG* at 34-35. We directed NFG to ensure that CAP households reverify income eligibility at least once every two years, stating:

> Although we recognize accepting a verbal declaration of income is less burdensome for both the customer and the CAP administrator, utilities have the responsibility to ensure that their CAPs – which are primarily funded by non-CAP residential customers – help only those customers that qualify for these programs.

Id. at 36.

Applying similar reasoning in this case, we agree with I&E that program benefits contingent on a poverty level should be based on a verified percentage of income, as the costs of these programs can have a significant impact on ratepayer bills. *See* 2020 Report on Universal Service Programs and Collections Performance of the Pennsylvania Electric Distribution Companies and Natural Gas Distribution Companies, Appendix 7, at 89. We have provided some flexibility to EDCs and NGDCs

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[141] *See National Fuel Gas Distribution Corporation's Universal Service and Energy Conservation Plan for 2017-2020 Submitted in Compliance with 52 Pa. Code § 62.4*, Docket No. M-2016-2573847 (Order entered March 1, 2018) (NFG).

concerning the manner in which these utilities document income and what forms of documentation are acceptable, and these matters are not necessarily addressed in each utility's USECP. We believe that these issues and other related issues are best addressed in a utility's low-income program committee, and, in this case, may be addressed as part of Aqua's Helping Hand Collaborative. In the meantime, Aqua can use the income documentation standards that the Peoples Companies currently use. For these reasons, we shall grant I&E's Exception No. 3, modify the ALJ's recommendation on this issue, and direct Aqua to require income documentation from an interested customer to certify income eligibility for participation in its CAP and upon recertification in a manner similar to that of the Peoples Companies. Within sixty days of the entry date of this Opinion and Order, Aqua shall submit a written plan describing the process it will use for certification and recertification of income eligibility for participation in its CAP. Such plan shall be filed with the Commission at this base rate proceeding Docket, with a copy served on BCS.

3. Application Process: Transitioning Helping Hand Customers to the New Customer Assistance Program

a. Positions of the Parties

The OCA recommended that current participants in the existing Helping Hand program be automatically enrolled in the new bill discount program. OCA M.B. at 168-73, 173-75. Similarly, CAUSE-PA recommended that Aqua develop a streamlined process for enrolling existing Helping Hand customers in CAP so the existing Helping Hand customers are not required to provide duplicative information to enroll in CAP. CAUSE-PA M.B. at 26 (citing CAUSE-PA St. 1 at 47).

Aqua explained that the lack of an automatic enrollment in CAP for existing Helping Hand customers is necessary to ensure customers are eligible. Aqua also explained that the application process for these customers is simple and does not require additional income documentation and, therefore, does not impose an incremental burden on CAP enrollees. Aqua states that it will notify Helping Hand customers by mail of the replacement and expansion of the existing program, which will detail the benefits of the CAP and encourage the customers to participate. Aqua notes that these customers can confirm their income through self-attestation and enroll over the telephone, online, or through a participating agency. Aqua M.B. at 149 (citing Aqua St. 10-R at 3). The Company believes that while it will encourage participation in the new program, existing Helping Hand customers should have the right to make an affirmative choice about whether to enter the new CAP. Aqua M.B. at 149.

b. Recommended Decision

The ALJ agreed with Aqua that the proposed application process to transition Helping Hand customers who qualify for the new CAP is reasonable and rejected the modification proposed by the OCA and CAUSE-PA. R.D. at 116.

c. OCA Exception No. 18 and Replies

In its Exception No. 18, the OCA argues that the ALJ erred in her decision to adopt Aqua's proposed application process for the new CAP. OCA Exc. at 29. The OCA avers that Aqua's existing Helping Hand customers should be automatically migrated to the new discount program, as the OCA's witness, Mr. Colton, and CAUSE-PA's witness, Mr. Geller, recommended. *Id*. at 30 (citing OCA St. 5 at 62-63; CAUSE-PA St. 1 at 46-48). The OCA states that the ALJ may not have appreciated the fact that the existing Helping Hand customers will lose their existing program benefits if the customers do not apply for the new combined discount/arrearage forgiveness program, because the existing Helping Hand program will no longer exist. OCA Exc. at 30 (citing Aqua St. 10-R at 2). As such, a group of customers that have not had their arrears completely forgiven and who do not apply to the new CAP, will no longer have the program forgiveness to complete reducing their arrearage balance. OCA Exc. at 30 (citing OCA St. 5-SR at 3). The OCA explains that arrearage forgiveness and the discount are designed to work together to address affordability, and separate enrollments and applications mean that not all low-income customers currently enrolled in the arrearage forgiveness program will continue to receive assistance either through the to-be-discontinued arrearage forgiveness program or the new bill discount program. The OCA asserts that this problem can be avoided by automatic migration to the new programs. OCA Exc. at 30.

In its Replies to Exceptions, Aqua avers that contrary to the OCA's claims, the enrollment process involves a single application, is simple, does not require additional income documentation and, therefore, presents no incremental burden. Aqua R. Exc. at 16-17. Aqua explains that existing Helping Hand customers will be asked to submit the application to ensure they are eligible for the new USP. Additionally, Aqua avers that it will actively encourage existing Helping Hand customers to enroll in the new program. *Id*. at 17.

d. Disposition

Given our determination, above, directing Aqua to require income documentation in order to certify income eligibility for participation in its CAP, it would not be feasible for Aqua to automatically migrate its existing Helping Hand customers into its new program. Aqua should implement its proposed application process to transition Helping Hand customers who qualify for the new CAP, subject to the modification that Aqua will now require income documentation for certification purposes rather than permitting potential program participants to confirm their income through self-attestation. Accordingly, we shall deny OCA Exception No. 18 and modify the ALJ's Recommended Decision consistent with this discussion.

4. Community Education and Outreach Plan

a. Positions of the Parties

The OCA witness, Mr. Colton, recommended that Aqua be directed to develop a Community Education and Outreach Plan (CEOP) that is directed toward areas within the Company's service territory with identified concentrations of low-income need. OCA M.B. at 162 (citing OCA St. 5 at 49-50). Mr. Colton specifically proposed that the CEOP incorporate the following elements:

> (1) the outreach should focus on community-based outreach; (2) the outreach is best implemented through "trusted messengers" that are part of the community toward which outreach is directed; (3) the outreach should be focused through boots-on-the-ground grassroots strategies. This boots-on-the-ground grassroots outreach out-performs outreach such as that provided through mass media, social media, utility-sponsored efforts, and top-down sponsored events; and (4) the outreach should be focused on efforts to go to where the community is rather than making the community come to the utility.

OCA M.B. at 162 (citing OCA St. 5 at 49). Mr. Colton stated that Aqua's CEOP should be designed to "identify the community partners with which it proposes to work," "identify the grassroots community organizations that will provide boots-on-the-ground efforts," and identify those times and places Aqua proposes to meet the community members where they "live, work, pray and play." OCA M.B. at 162-163 (citing OCA St. 5 at 49-50).

CAUSE-PA's witness, Mr. Geller, noted the low enrollment rates in Aqua's Helping Hand and Hardship Fund and concluded that as a result, there was a critical need for "enhanced, more concerted efforts to reach and enroll low-income consumers in Aqua's service territories in assistance programs." CAUSE-PA M.B. at 37 (citing

CAUSE-PA St. 1 at 64). Accordingly, CAUSE-PA recommended that Aqua should be required to develop and implement a comprehensive and coordinated consumer outreach and education plan that should:

> (1) be developed with input from the parties and interested stakeholders through Aqua's Helping Hand Collaborative; (2) set forth how Aqua will specifically promote each of its low income assistance programs; (3) be tailored to the demographics of Aqua's service territory; (4) include how Aqua will target outreach to specific communities, including those communities that have faced pervasive utility insecurity such as Black and Latinx communities; (5) specifically identify efforts to educate and enroll eligible customers at or below 50% FPL who represent those customers with the lowest incomes who struggle most profoundly to make ends meet; (6) translate all promotional and education materials into, at minimum, Spanish; and (7) identify resources and translation services for [limited English proficient/proficiency] LEP customers.

CAUSE-PA M.B. at 38 (citing CAUSE-PA St. 1 at 64).

Aqua agreed that a CEOP is an important component of universal service programs. Aqua M.B. at 150 (citing Aqua St. 10-R at 5). Aqua noted that its witness, Ms. Black, explained that Aqua's anticipated outreach and education will be similar to the CEOP that she developed for the Peoples Companies and will use the multiple touchpoints that utilities have with low-income customers and other entities, and that Aqua "plans to seek collaboration with other utilities to cross-promote its low-income programs with the goal of reducing barriers to participation and encouraging customers to avail themselves of all beneficial programs." Aqua M.B. at 151 (citing Aqua St. 10-R at 5-6). Aqua stated that its proposed CAP will include broad outreach and collaboration to ensure customers are made aware of the benefits available to them and are given significant opportunities to take advantage of the available benefits. Aqua M.B. at 151.

b. Recommended Decision

The ALJ recommended that Aqua continue to work to develop a CEOP in the manner that Ms. Black described in her testimony. The ALJ also stated that because Aqua does not appear to oppose CAUSE-PA and the OCA's recommendations for the development of the CEOP, Aqua should consider their input and incorporate their reasonable recommendations into the Company's outreach program. The ALJ reasoned that if Aqua does not adopt the OCA and CAUSE-PA's recommendations, the OCA and CAUSE-PA may seek appropriate relief from the Commission. R.D. at 118.

c. OCA Exception No. 19 and Replies

In its Exception No. 19, the OCA avers that the ALJ erred by not requiring Aqua to adopt the OCA and CAUSE-PA's recommendations for a CEOP. OCA Exc. at 30 (citing R.D. at 118; OCA M.B. at 161-64; OCA R.B. at 90-91). The OCA submits that the ALJ's recommended approach is not sufficient to address the problems that the OCA and CAUSE-PA identified regarding the development of a CEOP, and it is also not clear in what forum either the OCA or CAUSE-PA could seek appropriate relief. OCA Exc. at 30-31.

The OCA posits that while Aqua agrees that a CEOP is an important component of a universal service plan, the Company does not appear to adopt the OCA's recommendations regarding what that outreach should look like. OCA Exc. at 31. The OCA explains that it recommends that the Company incorporate a strategy of reaching low-income customers "where the community lives, works, plays and prays to be present at those locations rather than to sponsor 'events' that community members must attend." *Id*. (citing OCA St. 5 at 47-50). The OCA states that while the ALJ indicated that the OCA and CAUSE-PA may seek appropriate relief from the Commission if their recommendations are not adopted, there is not an appropriate alternative forum in which to seek relief. The OCA submits that unlike with energy utilities, Aqua would not need to submit a plan for approval of its CEOP, and there are not any Commission policy statements, applicable regulations, or statutory requirements specifically regarding what effective outreach and education for Aqua's discount and arrearage forgiveness programs should look like. The OCA avers that the instant proceeding is the forum in which the Company's proposed approach to education and outreach should be addressed. OCA Exc. at 31.

In its Replies, Aqua maintains its position in this proceeding that it has worked, and will continue to work, with the OCA and CAUSE-PA in the development of a CEOP, consistent with the Recommended Decision. As such, Aqua states that the OCA's concern is unfounded and its Exception should be denied. Aqua R. Exc. at 17.

d. Disposition

Upon review, we conclude that Aqua should continue to develop a comprehensive and coordinated CEOP with input from the Parties, including the OCA and CAUSE-PA, and from interested stakeholders through Aqua's Helping Hand Collaborative. Within six months of the entry date of this Opinion and Order, Aqua is required to file its CEOP with the Commission at this base rate proceeding Docket, with a copy served on the Commission's BCS and Office of Communications. As the CEOP is an evolving process, the Company must continue to work collaboratively with its Helping Hand Collaborative and the Commission's Office of Communications on any potential improvements and/or changes to its outreach and education initiatives after filing its first CEOP. We will also require Aqua to file annually, after its first CEOP filing, an updated CEOP at this base rate proceeding Docket until either its next base rate proceeding or another proceeding addressing its universal service programs. This will enable us to ensure that the Company is working with the collaborative to address stakeholder concerns or whether a separate proceeding is necessary to address outstanding matters. As such, we shall grant, in part, OCA Exception No. 19 and modify the ALJ's Recommended Decision consistent with our discussion on this issue.

B. Quality of Service

1. Unaccounted for Water

Unaccounted for water (UFW) is "Total Water Delivered for Distribution & Sale" minus "Total Sales" minus "Non-Revenue Usage and Allowance." R.D. at 119; OCA M.B. at 204; OCA St. 7 at 3-4. "Non-Revenue Usage and Allowance" includes "Main Flushing," "Blow-off Use," "Unavoidable Leakage," "Located & Repaired Breaks in Mains & Services" and "Other." Calculating UFW determines the amount of non-revenue water in a distribution system, helping to identify leaks and inaccurate meter readings. When UFW is measured, non-revenue water can be reduced which reduces chemical and power costs, provides for water conservation, and helps improve operational efficiency. *Id*. Levels of UFW above 20% are considered excessive by the Commission. 52 Pa. Code § 65.20(4).

a. Positions of the Parties

Aqua stated that its UFW is 20%, despite operational challenges of recently acquired water systems, and that no Party challenged its UFW. R.D. at 119; Aqua M.B. at 162. However, the OCA argued that Aqua should modify its reporting of UFW by being required to submit a Section 500 UFW calculation for each of its water systems and that the information submitted should be based on the same data that is required for American Water Works Association (AWWA) Audits and the annual Chapter 110

Reports submitted to the PADEP.[142] OCA M.B. at 206; OCA St. 7 at 6. Aqua opposed the modified reporting of UFW because Aqua's Section 500 Report is prepared on a consolidated basis and contains financial and operating data regarding operating the entire company. Aqua contended that it should not be treated differently by requiring it to prepare separate reports for operating divisions, that Section 500 Reports require different information than Chapter 110 Reports submitted to PADEP, and that AWWA Water Audits are a different measurement from UFW measurements prepared for the Section 500 Reports. In addition, Aqua noted that on November 18, 2021, the Commission issued a Notice of Proposed Rulemaking (NOPR) concerning proposed language for a regulation at 52 Pa. Code § 65.20(a), relating to water conservation measures. Aqua argued that committing to file separate Schedule 500 reports for each operating division while that NOPR is pending is redundant, time consuming and inefficient. R.D. at 120; Aqua M.B. at 162-63.

b. Recommended Decision

The ALJ found that the OCA did not demonstrate that its modification will result in a significant benefit to Aqua's customers. Therefore, the ALJ concluded that the OCA's proposed modification to the reporting of UFW should be rejected. R.D. at 120.

c. OCA Exception No. 24 and Replies

In its Exception No. 24, the OCA argues that the ALJ erred in concluding that Aqua should not be required to submit Section 500 reports for each of its distribution systems. The OCA disagrees that it has not demonstrated that its modification will result in a significant benefit to Aqua's customers and avers that requiring Aqua to submit a

[142] The Section 500 Forms are filed as part of the Company's PUC Annual Reports, and the Chapter 110 Reports are filed pursuant to the Company's requirements in its Annual Department of Environmental Protection (DEP) reports.

Section 500 Report for each of its distribution systems would identify levels of UFW which is a localized issue. The OCA contends that the identification and reduction of UFW benefits all water customers by reducing non-revenue water, which reduces chemical and power costs. OCA Exc. at 35.

In reply, Aqua asserts that Section 500 Reports are filed by utilities on a consolidated basis, and the OCA has offered no reason why Aqua should be singled out to prepare separate reports for operating divisions. Furthermore, Aqua avers that reporting on water loss in the annual Section 500 Report should not be revised while the Commission's NOPR, discussed above, which provides for AWWA water audit reports on an annual basis, remains pending. Aqua R. Exc. at 21.

d. Disposition

Upon review, we agree with the ALJ that the OCA's proposed modification to the reporting of UFW should be rejected. No significant benefits to Aqua's customers have been identified to treat Aqua differently by requiring it to prepare separate reports for operating divisions with different information than the financial and operating data that is currently provided in the Section 500 Report on a consolidated basis for the entire Company. In addition, we agree with Aqua that revising reporting requirements on water loss in the annual Section 500 Report should not be done at this time while the Commission's NOPR on this issue is pending. Therefore, we shall deny the OCA's Exception No. 24.

2. Pressure Measurements

The Commission's Regulations at 52 Pa. Code § 65.6(d) require a water utility to conduct pressure surveys by measuring pressures at "representative" points on its system:

> (d) *Pressure surveys.* At regular intervals, but not less than once each year, each utility shall make a survey of pressures in its distribution system of sufficient magnitude to indicate the pressures maintained at representative points on its system. The surveys should be made at or near periods of maximum and minimum usage. Records of these surveys shall show the date and time of beginning and end of the test and the location at which the test was made. Records of these pressure surveys shall be maintained by the utility for a period of at least three years and shall be made available to representatives, agents, or employees of the Commission upon request.

52 Pa. Code § 65.6(d).

With respect to variations in pressure levels, the Commission's Regulations require that a water utility shall maintain normal operating pressures between 25 pounds per square inch (psi) and 125 psi at the main, except that during periods of peak seasonal loads, the pressures at the time of hourly maximum demand may be between 20 psi and 150 psi, and that during periods of hourly minimum demand the pressure may not be more than 150 psi. 52 Pa. Code § 65.6.

a. Positions of the Parties

With respect to pressure surveys, the OCA argued that Aqua is not in compliance with 52 Pa. Code § 65.6(d) regarding the placement of the measurement point to track water pressure within Aqua's system because appropriately "representative points" means readings taken "at only a low and high pressure point." OCA M.B. at 210.

Aqua disagreed with the OCA's interpretation of 52 Pa. Code § 65.6(d) and maintained that its method of conducting pressure surveys on its system is compliant with the regulation. Aqua noted that it records pressures annually at more than 24,000 hydrants in its systems, and it described its operational procedures to monitor pressures by using local recordings as proxy checks for system performance. If an abnormality from the standard is observed, or if a customer reports a pressure problem, Aqua will conduct a follow-up investigation and address the issue. Aqua M.B. at 166-67; Aqua St. 9-R at 6.

In addition, the OCA recommended that Aqua should reduce pressures to all customers below 125 psi or be responsible for any damages resulting from higher pressures. Further, the OCA argued that Aqua should install pressure reducing valves for customers experiencing high pressures or be responsible for damages if it fails to reduce pressures to all customers below 125 psi. OCA M.B. at 210; OCA St. 7 at 13. The OCA cited an example of a water customer from Chesterbrook who testified at the public input hearing and described that he had experienced extremely high pressures, some as high as 200 psi, which caused damage to his home and neighborhood. Tr. at 230-43.

Aqua argued that the Commission recently considered and rejected a similar argument presented by the OCA in *Pa. PUC v. Pennsylvania-American Water Co.*, Docket No. R-2020-3019371 (Order entered February 25, 2021) (*PAWC*).[143] Aqua M.B. at 169-70. Aqua averred that, like *PAWC*, Aqua provides pressure in excess of 125 psi in situations where it is needed to serve customers in challenging terrain and to flow water between operating districts with different pressures. Aqua contended that the OCA's recommendation should be rejected. *Id*.

[143] In *PAWC*, the OCA recommended that PAWC should either provide a pressure reducer protecting a customer's service line or provide an insurance policy covering repair or replacement of the service as protection to service lines and inside plumbing in situations where PAWC elected to provide service at higher than 125 psi. The Commission concluded that it was not reasonable to "impose the requirement of insuring the customer service line upon the distribution utility." *PAWC* at 127.

b. Recommended Decision

Regarding the pressure surveys, the ALJ concluded that 52 Pa. Code § 65.6 does not define what is meant by "representative points" on a water system, and that if the Commission intended to limit pressure surveys to those taken at "one high and one low pressure point" on a system to be sufficiently "representative," the regulation would include that language. The ALJ found that there is no evidence that Aqua's current system is not reasonable for maintaining generally normal operating pressures between the range of 25 psi and 125 psi or that the points where measurements are taken are not sufficiently "representative." R.D. at 121-22.

The ALJ concluded that Aqua should not be directed to reduce upstream water pressures or install additional pressure valves in this proceeding. Noting that the Commission has repeatedly held that public utilities are not required to render perfect service, the ALJ found that a handful of customer experiences are not sufficient for the Commission to mandate operational changes on Aqua's distribution system at this point in time. However, the ALJ stated that as Aqua tracks pressure complaints more closely, it may be able to target areas that may require system improvements. R.D. at 123-24.

c. OCA Exception No. 25 and Replies

In its Exception No. 25, the OCA argues that the ALJ erred in concluding that Aqua should not be required to conduct pressure surveys at one high and one low pressure point on its system and that Aqua should not be required to reduce upstream water pressures or install additional pressure valves. The OCA contends that the intent of 52 Pa. Code § 65.6 is to ensure that water utilities are providing water service with pressures in reasonable ranges, and it is only logical and consistent with expert opinion that pressures be surveyed at a minimum at one high and one low point to get a fully comprehensive and useful understanding of the pressure reading of a system.

Furthermore, the OCA avers that allowing Aqua to continue providing service to customers at levels above 125 psi is not consistent with Aqua's obligation to provide safe, adequate and reliable service under 66 Pa. C.S. § 1501. OCA Exc. at 35-37.

In reply, Aqua argues that its system of pressure measurements satisfies the requirements of 52 Pa. Code § 65.6(d) and that the ALJ correctly rejected the OCA's arguments that Aqua's processes violate the regulation. In addition, Aqua states that the Recommended Decision recognizes that there are places in its system where higher pressures are necessary to ensure adequate water service to downstream customers. Aqua asserts that in the customer example from Chesterbrook offered by the OCA, this customer's property is located close to one of Aqua's largest treatment plants and pressures in excess of 200 psi are necessary to serve customers at higher elevations. Aqua references the Commission's decision in *PAWC* in arguing that it is not reasonable in certain situations to require Aqua to reduce pressures or to insure the customer against damages if the customer's required reducing valve fails. Aqua R. Exc. at 21-22.

d. Disposition

With respect to the pressure surveys, we agree with the ALJ's conclusion that, in promulgating the regulation at 52 Pa. Code § 65.6(d), if the Commission intended to limit pressure surveys in any way to define the meaning of "representative points," *e.g.*, to those taken at one high and one low pressure point, the regulation would include such language. Without such a requirement, the ALJ found that there is no evidence that Aqua's current system is not reasonable for maintaining generally normal operating pressures or that the points of measurement are not sufficiently representative. Therefore, we agree that Aqua's system of pressure measurement satisfies the requirements of 52 Pa. Code § 65.6(d).

Additionally, we agree with the ALJ that Aqua should not be directed to reduce upstream water pressures or install additional pressure valves based upon this proceeding. While we are sympathetic to the experience of the customer from Chesterbrook of failing pressure valves and property damage, the Commission has repeatedly held that public utilities are not required to render perfect service. *Rounce v. PECO Energy Co.,* Docket No. C-2015-2506941 (Order entered December 9, 2016); *Bertsch v. PPL Elec. Util. Corp.*, Docket No. C-2011-2251784 (Order entered April 2, 2012). Although a few customer experiences are not sufficient for the Commission to mandate operational changes on Aqua's distribution system at this point in time, we encourage Aqua to identify and explore ways to target areas that may benefit from system improvements as it investigates and tracks individual pressure complaints. We shall deny the OCA's Exception No. 25.

3. Isolation Valves

Isolation valves are installed on water mains so that the flow of water can be shut off in sections of the distribution system in case of a water main break or for other main repairs and replacements. Aqua M.B. at 170. Exercising an isolation valve means operating the valve through complete full open and close cycles until it operates with little resistance. Exercising isolation valves prevents them from seizing up and getting stuck due to corrosion or other deposits. An isolation valve that cannot be fully closed will increase water loss during a water main break. Inoperable valves will need to be replaced or repaired. OCA M.B. at 211-12; OCA St. 7 at 14.

a. Positions of the Parties

With respect to critical isolation valves, Aqua stated that all of its 270 such valves have been identified and currently have an exercising schedule within Aqua's work order management system, and that it exercises these valves at least once every four years. Aqua M.B. at 171. The OCA determined that Aqua's exercising schedule for its critical isolation valves is reasonable and recommended that any critical isolation valves that could not be exercised should be repaired or replaced as soon as practicable after they are found to be inoperable. OCA M.B. at 212.

For non-critical isolation valves, Aqua operates according to a twelve-year inspection and exercising program. Aqua averred that it has committed to various non-critical valve inspection measures as part of its 2020 management audit with the Commission. Aqua M.B. at 171-172. The OCA argued that Aqua's schedule to inspect non-critical isolation valves is too long and that they should be inspected on a five-year cycle. OCA M.B. at 213. Aqua contended that the cost of the OCA's recommendation, for which the OCA did not provide any estimates, may exceed any operational benefit due to the amount of time and additional workforce needed to implement it, and that the proposed timeline is inefficient and redundant. Aqua M.B. at 172; Aqua St. 9-R at 13-14.

b. Recommended Decision

The ALJ found that the OCA did not meet its burden of proving that requiring a five-year inspection cycle for non-critical valves is necessary or will derive a benefit to Aqua's system commensurate with the cost of the program. However, the ALJ recommended that the Commission direct Aqua to develop an isolation valve inspection and exercise program, to be implemented no later than 180 days from the effective date of rates resulting from this proceeding, which establishes a defined schedule to exercise each of its non-critical isolation valves within a set inspection cycle and, subsequently, maintain records of its attempts to inspect and exercise its isolation valves noting whether it was successful. R.D. at 125.

c. Aqua Exception No. 13, OCA Exception No. 26, and Replies

In its Exception No. 13, Aqua argues that the ALJ erred by requiring the Company to develop an isolation valve inspection and exercise program, because it has already developed an appropriate inspection and exercise program. Further, Aqua contends that it has made commitments through its 2020 management audit relating to the inspection of non-critical valves, and it committed to ensure the exercising of these valves is completed over a twelve-year period. Aqua asserts that the ALJ's recommendation is duplicative of Aqua's existing program and commitments and should be rejected. Aqua Exc. at 38-39.

In reply, the OCA agrees with the ALJ's recommendation that Aqua must develop an isolation valve inspection and exercise program. The OCA disagrees with Aqua that it has already developed such a program and that the ALJ's recommendation is duplicative of such program. Rather, the OCA contends that certain findings in Aqua's 2020 management audit state that "several aspects of a comprehensive critical valve testing program are missing or in progress, and the company should expand the program to track testing and operation of non-critical valves…" and Aqua's operating procedure "does not include information on valve inspection, scheduling, or valve criticality – all of which would be critical components of a valve inspection manual or program." OCA R. Exc. at 24 (citing *Aqua Pennsylvania, Inc., Peoples Natural Gas Company LLC, Peoples Gas Company LLC, Management and Operations Audit*, Docket Nos. D-2020-3018771, D-2020-3018773, and D-2020-3018774 (issued April 2021) (*Aqua 2020 Management Audit Report*)). Furthermore, the OCA argues that a specific replacement time for non-critical valves has not been approved by the Commission and Aqua has not provided support for the longer twelve-year exercising schedule. The OCA asserts that the Commission should adopt the ALJ's recommendation to direct Aqua to develop an isolation and inspection exercise program to be implemented no later than

180 days from the effective date of rates resulting from this proceeding. OCA R. Exc. at 24-25.

In its Exception No. 26, the OCA argues that the ALJ erred in concluding that Aqua should be required to inspect non-critical isolation valves every twelve years instead of five years. The OCA avers that it demonstrated that a five-year inspection cycle would provide a benefit to Aqua and its customers. OCA Exc. at 37-38.

In reply, Aqua contends that the ALJ correctly denied the OCA's recommendation that Aqua implement the OCA's proposed five-year inspection cycle for non-critical valves. Aqua reiterates that it has made commitments through its 2020 management audit to exercise its non-critical valves over a twelve-year period, and that it has identified all valves in its system and is developing a schedule for exercising the non-critical isolation valves. Also, Aqua avers that the OCA's proposal is not supported by cost estimates for the amount of time and additional workforce that would be needed. Aqua R. Exc. at 22.

d. Disposition

Upon review of the record, we conclude that the OCA did not meet its burden of proving that requiring a five-year inspection cycle for non-critical isolation valves is necessary or will be cost-beneficial to Aqua's system. The OCA did not provide any cost estimates for the implementation of its recommended five-year program. Without any cost estimates, it is not possible to determine whether any benefits from the accelerated program will be commensurate with its costs. The costs associated with any additional time and workforce needed for the program could exceed its operational benefit and render it inefficient and redundant. For these reasons, we will not require Aqua to implement a five-year inspection cycle for non-critical isolation valves. Accordingly, the OCA's Exception No. 26 shall be denied.

We will, however, adopt the ALJ's recommendation and direct Aqua to develop an isolation valve inspection and exercise program, to be implemented no later than 180 days from the effective date of rates resulting from this proceeding, which establishes a defined schedule to exercise each of its non-critical isolation valves within a set inspection cycle and requires Aqua to maintain records of its attempts to inspect and exercise its isolation valves noting whether it was successful. Although Aqua contends that such a directive is duplicative because it has already developed an appropriate inspection and exercise program and made commitments through its 2020 management audit relating to the inspection of non-critical valves, we agree with the ALJ that the development of a non-critical isolation valve inspection and exercise program at this time is reasonable. The findings referenced by the OCA from the Commission's 2020 Aqua management audit that Aqua should expand its valve inspection program to track testing and operation of non-critical valves and that its operating procedure should include information on valve inspection, scheduling, or criticality, along with the fact that a specific replacement time for non-critical valves has not been approved by the Commission, support the ALJ's recommendation to develop a more formal valve inspection program. *See* OCA R. Exc. at 24 (citing *Aqua 2020 Management Audit Report*). Therefore, Aqua's Exception No. 13 will be denied.

4. Fire Hydrants

Aqua has over 21,000 public fire hydrants throughout its systems. In response to discovery, Aqua identified sixteen public fire hydrants on its systems that cannot provide the minimum fire flow of 500 gallons per minute (gpm) at 20 psi. Aqua M.B. at 172.

a. Positions of the Parties

The OCA recommended that each of the sixteen fire hydrants that cannot provide the minimum fire flow should be marked as such so that they will only be used for flushing and blow-offs and Aqua should provide confirmation to the OCA and other parties when this is completed. OCA M.B. at 213; OCA St. 7 at 17. Aqua stated that it has planned main replacement projects to address these hydrants within the next three years and, during this time, Aqua will attempt to either find alternative locations for the hydrants or remove them. Aqua M.B. at 172; Aqua St. 9-R at 15. The OCA agreed with this approach, so long as the hydrants will be marked and only used for flushing and/or blow-offs until they are moved or replaced. OCA M.B. at 213-14; OCA St. 7SR at 8.

b. Recommended Decision

The ALJ stated that the OCA and Aqua largely resolved their disputes regarding Aqua's plan to address the sixteen fire hydrants in its system that cannot provide the minimum fire flow of 500 gpm at 20 psi. Given the limited number of fire hydrants at issue and the importance to fire companies to know that these hydrants are not reliable for fire protection, the ALJ found that the OCA's recommendation that Aqua should mark the hydrants for only flushing and/or blow-offs until they are moved or replaced, and report to the OCA and other Parties when this is completed, is reasonable and should be adopted. R.D. at 125.

c. Disposition

No Party filed Exceptions on this issue. Finding the ALJ's recommendation to be reasonable, we shall adopt it without further comment.

5. Flushing

Flushing addresses sediments that build up in pipes that may affect the taste, clarity, and color of water. There are no Commission or PADEP requirements for main flushing. In a discovery response, Aqua indicated that all systems were flushed in 2020 under its main flushing program, but six systems were not flushed in 2019 due to staffing issues. OCA M.B. at 214; OCA St. 7 at 17.

a. Positions of the Parties

The OCA recommended that Aqua improve its flushing program in its Southeast Pennsylvania (SEPA) division by flushing the system once every three years because there are a substantial number of complaints regarding flushing-related issues which would likely be eliminated under a regular flushing program. OCA M.B. at 214.

Aqua disagreed with the OCA's recommendation. Aqua argued that the OCA offered no evidence, and that there is no industry standard, supporting a three-year flushing schedule. Also, Aqua averred that flushing is labor-intensive, somewhat disruptive and can result in significant non-revenue water volume. Aqua stated that certain factors, including water quality samples, customer issues, system geometry, daily water volume in an area, and proximity to wells and tanks, dictate how and when flushing occurs. Aqua contended that it should retain flexibility regarding flushing its distribution system and a three-year schedule is not warranted. Aqua M.B. at 174-175; Aqua St. 9-R at 17-18.

b. Recommended Decision

The ALJ noted that a three-year flushing program may eliminate customer complaints and the need for Aqua to assess certain factors in determining whether and when to flush the system. However, the ALJ found that, based on Aqua's witness testimony that flushing can be labor intensive and result in UFW, it is not possible to conclude that it is reasonable to impose the costs on ratepayers for a three-year flushing program which may or may not result in the benefits identified by the OCA. R.D. at 126.

c. OCA Exception No. 27 and Replies

In its Exception No. 27, the OCA argues that the ALJ erred in concluding that Aqua should not be required to flush its SEPA system every three years. The OCA asserts that Aqua did not offer support for its position that flushing a system can be labor intensive and result in UFW, and it contends that a three-year flushing program is reasonable and consistent with industry standards. OCA Exc. at 38.

In reply, Aqua contends that the OCA's proposal "is an expensive and a wasteful solution in search of a problem." Aqua avers that the number of customer complaints does not suggest a serious water quality issue requiring a change to its flushing procedures. Furthermore, Aqua argues that the OCA's proposal would result in additional lost water from increased flushing and add to labor and water treatment costs. Aqua R. Exc. at 22-23.

d. Disposition

Upon review of the record, we agree with the ALJ that it is not possible based on the record to determine whether any benefits of a three-year flushing program will outweigh the costs associated with it. While such a program may reduce customer complaints and provide for a pre-determined flushing frequency, as the OCA argues, flushing the system can be labor intensive, disruptive and result in UFW, according to Aqua. Without any additional evidence or a clear industry standard supporting a three-year flushing program, we find that requiring Aqua to flush its SEPA system every three years is not warranted. Therefore, we shall deny the OCA's Exception No. 27.

6. Per- and Polyfluoroalkyl Substances (PFAS)

Aqua maintains a website, www.waterfacts.com, with information about its testing and treatment for PFAS contamination in its water supplies. The most recent test results for some water sources were from 2016, 2017 and 2018, without explanation why more recent test results were not provided. Aqua M.B. at 175; OCA M.B. at 215; OCA St. 7 at 19.

a. Positions of the Parties

The OCA indicated that its understanding that testing was stopped at certain sites was because the test results indicated less than 13 parts per trillion for PFAS, which is Aqua's standard, and that Aqua ceases testing for sources that test below 13 parts per trillion. The OCA recommended that Aqua should add a statement to its website explaining why testing was stopped for water sources that it no longer tests for PFAS. Aqua agreed to implement the OCA's recommendation and stated it will include clarifying comments on its website regarding the reasons testing ceased at certain sites. Aqua M.B. at 175-76; Aqua St. 9-R at 19; OCA M.B. at 215; OCA St. 7 at 19.

b. Recommended Decision

The ALJ found that as no other party presented testimony on this issue, and Aqua agreed to the OCA's recommendation regarding PFAS reporting, Aqua's PFAS procedures should be accepted by the Commission.

c. Disposition

No Party filed Exceptions on this issue. Finding the ALJ's recommendation to be reasonable, we shall adopt it without further comment.

C. Customer Service

Under the *Aqua-Peoples Settlement*, the settling parties agreed that Aqua would commit to the following "Customer Service" improvement metrics:

> 83. Aqua commits to improve Aqua's call center performance to meet or exceed the same performance standards that the Peoples Companies agreed to meet in the 2013 Settlement concerning the acquisition of Equitable Gas Company (Docket No. A-2013-2353647 et al.) for the following three metrics in each of the five calendar years (2020-2024) following closing:
>
> i. percent of calls answered within 30 seconds of at least 82%,
> ii. busy-out rate of no more than 0.25%,
> iii. average call abandonment rate that is no higher than 4% for 2020-2021, no higher than 3% for 2022-2023, and no higher than 2.5% for 2024.

Aqua-Peoples Settlement at 146-147.

In this proceeding, the OCA and CAUSE-PA asserted that Aqua failed to comply with certain of the customer service related commitments made by Aqua in the *Aqua-Peoples Settlement*. R.D. at 127-131. As will be discussed more fully below, the OCA challenged Aqua's compliance with Paragraph No. 83, above, of the settlement commitments. In this regard, the OCA challenged Aqua's compliance with: (1) percent of calls answered within 30 seconds of at least 82%; and (2) average call abandonment rate that is no higher than 4% for 2020-2021, no higher than 3% for 2022-2023, and no higher than 2.5% for 2024. *See* OCA M.B. at 188-193. The OCA stated that Aqua met the busy-out rate standard, but for reasons argued in its OCA St. 6, Aqua had not met the standards for calls answered and average call abandonment rate.

The OCA also challenged Aqua's compliance with Paragraph 85 of the *Aqua-Peoples Settlement, infra,* regarding the Company's commitment to complete a root cause analysis (RCA) of customer complaints. *See* OCA M.B. at 193-94. In addition, the OCA argued that Aqua's failure to comply with customer service related issues, in addition to other considerations, were an additional reason to reject the Company's request for a management performance adjustment to its ROE, discussed, *supra*. *See* OCA MB at 75-77; 181-82; 204.

1. Calls Answered Commitment Under the *Aqua-Peoples Settlement*

a. Positions of the Parties

The OCA asserted that Aqua was not in compliance with the calls answered commitment under the *Aqua-Peoples Settlement*. The OCA proffered its calculation of the utility's percentage of calls in which a customer affirmatively seeks to talk to a live representative. OCA M.B. at 190 (citing OCA St. 6 at 10); *also*, OCA Exh. BA-2 for calculation of annual average results for each of the performance standards using monthly information provided by Aqua. According to the calculations of the OCA witness Ms. Barbara A. Alexander, as measured by the calls in which the customer selects the option to speak with a representative, the annual calls answered average for 2019 was 70.56%, for 2020 was 72.86%, and for 2021 through July was 50.64%. *Id.*

Based on the foregoing, the OCA witness, Ms. Alexander, pointed out that Aqua has never met the 82% call answering standard as measured by the typical measurement of the percentage of calls in which the customer affirmatively seeks to talk to a live representative.

Additionally, the OCA took issue with Aqua's calculation of the percentage of calls answered within 30 seconds based on the Company's use of "aggregated" data. Aqua used data from a combination of the results for customers seeking to speak to a representative with all calls handled without that request through its automated menu, Interactive Voice Response (IVR), system. Use of data from the IVR system was described as an "aggregate" of data. The OCA found use of aggregate data to be objectionable as it would, in its view, skew the data results.[144] OCA St. 6 at 10.

In response to the position of the OCA concerning Aqua's compliance with the percentage of calls answered, Aqua noted that OCA witness Ms. Alexander acknowledged that the Company's percentage exceeded the 82% threshold for both 2019 and 2020. Aqua M.B. at 184. Consequently, the disagreement between Aqua and the OCA regarding this metric centered upon the inclusion of calls handled by Aqua's IVR system in calculating the calls answered percentage. *Id*.

Aqua explained that the IVR is an automated way to service customers that call in with questions or concerns. *See* Aqua St. 10-R at 15-16. Aqua cites to the applicable terms of the *Aqua-Peoples Settlement,* Paragraph No. 83, and argues that the Peoples Companies include IVR contacts in calculating service level performance. Aqua continues that the use of IVR contacts data is a standard calculation in measuring contact

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[144] In response to discovery, Aqua stated that it utilizes two call centers located in Illinois and North Carolina which handle calls from Pennsylvania customers. OCA St. 6 at 9. The Merger Settlement requires annual average performance standards in the three areas mentioned above [Aqua-Peoples Settlement Paragraph No. 83] that can be measured to reflect the performance provided to Pennsylvania customers. Since both call centers handle calls from all of Aqua's customers in several states, the performance standards reflect the average of all calls at both call centers. *See* OCA St. 6 at 9.

center performance. Based on the foregoing, Aqua submits that the position of the OCA, that the IVR system should not be "aggregated" with the Company's person-to-person telephonic contacts, should be rejected.

b. Recommended Decision

The ALJ agreed with Aqua that the Company met its commitment under the *Aqua-Peoples Settlement* to answer 82% of customer calls within 30 seconds. The ALJ rejected the position of the OCA that use of the IVR data to calculate the Company's performance related to the call center standards metric, made Aqua's data unreliable and, therefore, not in compliance with the terms of the settlement. The ALJ agreed that use of aggregate data was consistent with the settlement and reasonable because it is the standard used by the Peoples Companies. R.D. at 128.

c. OCA Exception No. 20 and Replies

In its Exception No. 20, the OCA disagrees with the ALJ that use of aggregate data is reasonable. The OCA argues that the calls answered standard should be measured only by the number of customers who choose to speak with a representative because use of aggregate data, which also includes customers who use the IVR system (and do not attempt to reach a representative), skews the results. OCA Exc. at 31-32. The OCA notes that these calls are clearly "answered" within less than thirty seconds, but the calls are irrelevant to the issues discussed and agreed to in the *Aqua-Peoples Settlement*. OCA Exc. at 32.

Therefore, based on its position that use of the IVR data (or aggregated data) is not reasonable under the *Aqua-Peoples Settlement*, the OCA argues that the Commission should adopt its recommendation. *See*, *i.e.,* OCA M.B. at 204, pertaining to the directive for Aqua to issue a compliance document. The OCA submits that due,

inter alia, to Aqua's failure to meet the obligations of the *Aqua-Peoples Settlement*, the Commission should reject Aqua's claim for exemplary management performance.
OCA Exc. at 32

In its Replies to Exceptions, Aqua distinguishes the contentions asserted by the OCA about what may be "reasonable." According to Aqua, the OCA's position disregards the clear language of the commitment of the *Aqua-Peoples Settlement*. In this regard, Aqua argues the express language of the settlement commits the Company to improve its call center performance to meet or exceed the same performance standards that the Peoples Companies are under. Aqua continues that this is the result of the metric - – percentage of calls answered within 30 seconds of at least 82%. Because the Peoples Companies include IVR contacts in calculating service level performance, which is a standard calculation in measuring contact center performance, Aqua argues that it should be permitted to do so and that it is reasonable to do so in its calculation. Aqua R. Exc. at 18-20.

d. Disposition

On consideration of the record evidence, we shall deny the OCA's Exception No. 20, consistent with the discussion herein and adopt the recommendation of the ALJ. There is no dispute that the analogue for this metric is the performance metric adopted by the Peoples Companies. Based on the use of aggregated data for the calculation as used to measure the performance of the Peoples Companies, we agree with the recommendation of ALJ Long that use of this data is acceptable for Aqua. When viewed in this light, it appears that Aqua has complied with its commitments.

Based on the foregoing, we will deny the OCA's Exception No. 20 in full recognition that, in any future proceeding, where the metric is shown to inaccurately reflect Pennsylvania-specific conditions, its calculation may be revisited.

2. Calls Abandonment Commitment Under the *Aqua-Peoples Settlement*

a. Positions of the Parties

Under the *Aqua-Peoples Settlement*, Aqua committed to: "[an] average call abandonment rate that is no higher than 4% for 2020-2021, no higher than 3% for 2022-2023, and no higher than 2.5% for 2024." The OCA noted that Aqua's annual call abandonment rate metric had not been met. *See* OCA St. 6 at 10. The OCA, through its witness Ms. Alexander, observed that the call abandonment rates were: 4.56% in 2019, 4.32% in 2020, and 13.15% in 2021, through July. *Id*.

The OCA also, as noted, objected to Aqua's measure of the call abandonment rate by combining the performance when customers affirmatively seek to speak with a customer service representative with all calls handled via the IVR system. The OCA argued that use of the IVR system data results in an inaccurate measurement of customer experience for those attempting to reach a customer service representative. OCA St. 6 at 10.

Aqua conceded that it had not, for the applicable period, met the percentage of average call abandonment metric commitment of the *Aqua-Peoples Settlement*. Aqua explained, however, that unanticipated circumstances outside of its control were substantial factors in preventing the Company from express compliance. *See* Aqua M.B. at 185-86.

Aqua, through its witness, Ms. Black, explained that the failure to meet the metric was primarily attributed to unanticipated United States Postal Service (USPS) delays. Aqua explained that the unanticipated USPS delivery delays caused many customer bills to be delivered late and resulted in higher-than-normal call volumes.

The impact of the postal service delay and severe weather events in meeting this metric was identified in an annual report filed on February 1, 2021.

Aqua noted that the *Aqua-Peoples Settlement* contemplated a situation where the Company may miss a benchmark and such failure would be addressed in collaboratives as contemplated by the terms of the *Aqua-Peoples Settlement*. Under the terms of the settlement, Aqua is required to compile an annual report to apprise stakeholders of its compliance with the settlement terms.

b. Recommended Decision

On consideration of the position of the Parties, the ALJ agreed with Aqua. The ALJ noted that the *Aqua-Peoples Settlement* contemplated a situation where events outside of the Company's control that prevent compliance with the literal terms of the settlement commitments could occur. She found that Aqua transparently explained in the February 1st report the reason for its failure to meet the call abandonment benchmark for 2020-21. The events resulting in Aqua's failure to meet the settlement commitment were viewed as an isolated situation and did not, in her opinion, equate to a failure to comply with the settlement. R.D. at 128.

c. OCA Exception No. 21 and Replies

In its Exception No. 21, the OCA disagrees with and, therefore, excepts to, the ALJ's conclusion that Aqua "[s]hould be excused from its obligation to reduce its average call abandonment rate to 4% or less." OCA Exc. at 32.

The OCA argues that the evidence shows that as of July 2021, the call abandonment rate was 13.15%, compared to a rate of 4.56% in 2019. The OCA argues that, in the year before and in the partial year following the unusual circumstances in late 2020, Aqua never met the "no higher than 4%" metric for its call abandonment rate, even when calculated using the aggregate calls that included IVR data. OCA Exc. at 32-33 (citing OCA St. 6SR at 5; OCA M.B. at 192-93).

The OCA, contrary to the conclusion of the ALJ, takes the position that Aqua's failure to achieve its commitment level was not an isolated event that happened because of unforeseen circumstances. The OCA points out that the Company has not met the 4% abandonment rate in any of the last two and one half years. OCA Exc. at 33.

In its Replies to Exceptions, Aqua stresses two points: (1) the settlement commitment did not become effective until after the merger was approved by the Commission in 2020, and thus prior performance data under this metric is not relevant to assess its compliance with the commitment; and (2) the ALJ concluded that the *Aqua-Peoples Settlement* contemplated that unexpected circumstances could prevent compliance. Based on the foregoing, the Company maintains that the failure to meet this metric is, in fact, an isolated situation which does not equate to a failure to comply with the settlement commitment. Aqua R. Exc. at 19.

d. Disposition

On consideration of the positions of the Parties, we shall deny the Exceptions of the OCA in this matter. We note that there is a substantial disparity in the percentage of calls abandoned for year 2021 (as of July 2021, 13.15 %; *see* OCA Exc. at 32). While we find the substantial difference in the target percentage under the metric and the actual performance of Aqua to be a concern, we accept the reasoning of the presiding ALJ that the Company provided a reasonable basis to account for the disparity. On balance, we agree that the substantial difference in the abandoned call percentage for the calendar year 2021 resulted from unanticipated conditions and is an isolated event. While the OCA notes that the Company has never met its target prior to the periods of time of the 2021 report, the Company notes that the approval of the merger conditions in 2020 renders this data not material to our consideration of the year at issue, 2021.

Based on the foregoing, the OCA's Exception No. 21 is denied consistent with the discussion in this Opinion and Order. We advise the Parties that the annual report will provide a basis for cooperation between interested stakeholders should further concerns arise regarding compliance.

3. Commitment to Complete a Root Cause Analysis (RCA) of Customer Complaints

a. Positions of the Parties

The OCA explained that this area of concern arises pursuant to Paragraph No. 85 of the *Aqua-Peoples Settlement*. Paragraph No. 85 is reprinted below:

> 85. Aqua PA will develop a system to track Aqua PA customer complaints in a live Excel spreadsheet, consistent with Paragraph 47 in the Joint Petition for Settlement submitted in Aqua PA's recent base rate case (Docket Nos. R-2018-3003558 and R-2018-3003561). Aqua PA will review this information and conduct a root cause analysis [(RCA)] of adverse trends at least annually.

Aqua-Peoples Settlement at 147.

The OCA took the position that Aqua failed to comply with the development of a RCA.[145] *See* OCA M.B. at 193-94. The OCA asserted that Aqua has not provided requested information on the methodology and timetable for the completion of the RCA contemplated by the *Aqua-Peoples Settlement*. The OCA further stated that Aqua has not indicated a methodology for tracking whether its responses to customer disputes or complaints were incorrect or improper, which, we are advised, is a key component of any RCA of customer complaints.[146] *Id.*

Aqua, through its witness, Ms. Black, acknowledged that the RCA has not been completed. Aqua referenced a "live spreadsheet" that has not yet been finalized. Aqua M.B. at 187. Aqua attributed the lack of finalization to the fact that it has been working with the OCA to develop the spreadsheet based upon the OCA's requested parameters. *Id*. (citing Aqua St. 10-R at 17).

b. Recommended Decision

The ALJ concluded that Aqua sufficiently demonstrated its good faith efforts to come into compliance with the benchmarks set forth in the *Aqua-Peoples*

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[145] A RCA requires a fundamental review of the policies and practices that resulted in an informal customer complaint and the internal evaluation of how to prevent the complaint or fix the underlying cause. *See* OCA St. 6 at 12. The OCA acknowledged that Aqua provided a confidential spreadsheet of complaints and their "root cause," but did not provide an actual analysis of the root cause. OCA M.B. at 193-194.

[146] As the OCA witness, Ms. Alexander, noted, "[t]his lack of analysis of customer complaint trends and identification of the root cause for any complaint trends is also troubling in light of the volume of 'justified' complaints and 'notices of infractions' from the Commission's [BCS] after that office's handling of informal complaints submitted by Aqua customers." OCA St. 6 at 13.

Settlement concerning the development of a RCA. R.D. at 129. The ALJ acknowledged that the development of a RCA is an ongoing process.[147]

c. OCA Exception No. 22 and Replies

In its Exception No. 22, the OCA argues that Aqua has not complied with the commitment to conduct a RCA of customer complaint data consistent with the *Aqua-Peoples Settlement*. The OCA stresses that the terms of the settlement required Aqua to develop a system to track Aqua customer complaints in a live Excel spreadsheet and to review this information and conduct a RCA of adverse trends at least annually. The OCA takes the position that Aqua has failed to do this, and it disagrees with the ALJ's conclusion that Aqua's compliance with this settlement obligation should not be determined based upon "good faith efforts." OCA Exc. at 33.

The OCA further argues that, based on a comparison of Aqua's performance compared to other utilities, such comparison shows why it is "critical" for Aqua to comply with this term of the *Aqua-Peoples Settlement* in this regard.[148] The OCA points out that Aqua had a high number of customer complaints and, in order to address Aqua's high percentage of justified complaints, it asserts that the Company should be required to conduct a RCA of customer complaint data to spot issues and concerns that require attention and potential changes in policies or processes as soon as practicable. OCA Exc. at 33.

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[147] The ALJ further noted that, upon the conversion to SAP, Aqua's witness, Ms. Black, stated that the Company's RCA efforts can be enhanced by increasing the visibility of case trends through enhanced reporting of case types. R.D. at 129.

[148] In 2020, Aqua had the highest number of "justified" complaints compared to other Pennsylvania water utilities; 16% of the closed and evaluated customer complaints were justified compared to 5% for other major water utilities. *See* OCA Exc. at 33 (citing 2020 Utility Consumer Activities Report and Evaluation at 12; OCA M.B. at 180; OCA R.B. at 110). In October 2021, Aqua's justified average complaint percentage was 13%. OCA Exh. BA-5; OCA R.B. at 111. *Id*.

For these reasons, the OCA submits that Aqua is not in compliance with this term of the settlement. Therefore, the Commission should modify the Recommended Decision and adopt the OCA's recommendation. OCA Exc. at 33-34.

In its Replies to Exceptions, Aqua explains that it has been attempting to work collaboratively with the OCA to develop the spreadsheet's parameters. Aqua R. Exc. at 20. With respect to the RCA, Aqua further explains that the RCA occurs on an on-going basis. The Company states that, if an isolated employee error is identified, coaching on compliance is provided. If multiple similar complaints are received, the issue is escalated to the customer contact team for review. *Id*.

Aqua concludes its Replies by noting that it is working to "enhance" and "formalize" the RCA process, which will be facilitated by Aqua's upcoming conversion to the SAP operating system. Based on this representation, Aqua asserts that the OCA's contentions regarding its RCA efforts are without merit and that the OCA's Exception should be denied. Aqua R. Exc. at 20.

d. Disposition

On consideration of the record, we shall grant the OCA's Exception No. 22, in part, and deny it, in part. The Parties appear to have little to no disagreement concerning the "live" spreadsheet data. The controversy appears to surround the use of the spreadsheet data in development of the RCA. We do not, therefore, dismiss, out of hand, the concerns expressed by the OCA in the development of the RCA.

The Company's commitment, as memorialized in Paragraph No. 85 of the *Aqua-Peoples Settlement,* cross-references Paragraph No. 47 of the 2018 Settlement, which was approved by the Commission in the *Aqua 2018 Rate Case*. Paragraph No. 47 of that 2018 Settlement reads as follows:

> 47. The Company shall continue to provide water and wastewater customer complaints in a live Excel spreadsheet that shall be made available in future general rate proceedings. The water and wastewater customer complaint logs shall contain separate searchable columns for date of complaint, street number, street name, city (zip code is preferable), and code for the type of complaint. The Company and OCA agree to continue to discuss how to incorporate into a live Excel spreadsheet the following additional information regarding whether a Company employee made a site visit, if the problem was the responsibility of the Company or the customer, and the date the complaint was resolved. The Company and the OCA agree to have that discussion within 90 days after the entry of a final order in this proceeding. Additionally, the Company agrees to provide a legend explaining the abbreviations used in the complaint logs.

Our review of the cross-referenced language connotes a more collaborative process between the OCA and Aqua was intended for the development of the RCA that goes beyond the submission of live spreadsheet data. Based on our review, we direct Aqua, the OCA and I&E to engage in collective exchanges regarding the spreadsheet data and cooperatively apprise each of how this data will be developed into a RCA that can reflect meaningful trends so as to, potentially, reduce contested issues in future proceedings. Accordingly, we shall grant the OCA's Exception No. 22, in part, and deny it, in part.

4. Management Performance Adjustment to Aqua's ROE Based Upon Asserted Levels of Customer Satisfaction

a. Positions of the Parties

The OCA's overall position was in vigorous opposition to the base rate increase request of Aqua. *See*, *e.g.,* OCA M.B. at 1-16. In addition to its objection to any increase in rates due to the adverse economic impact of the COVID-19 pandemic on the service territory of Aqua, the OCA also took the position that Aqua's customer service performance was below that of comparable utilities. The OCA, through its witnesses, Ms. Alexander and Mr. Colton, addressed areas where Aqua was alleged to have failed to meet basic standards of utility performance pursuant to Sections 526 and 1501 of the Code, 66 Pa. C.S. §§ 526, 1501.

Based on the foregoing, as well as other factors discussed in Section X.D.2 of this Opinion and Order, *supra*, the OCA opposed Aqua's request for a management performance adjustment to its ROE. The OCA noted that the request was not supported but was refuted by the testimony of its witness Mr. David J. Garrett, who provided specific analyses of customer service and customer assistance measures. Namely, as noted in Section X.D.2, *supra,* the OCA, through its witness Mr. Garrett, testified that the Company has not conducted any comparative analyses to determine if Aqua's management performance is any different than other regulated utilities, in or out of its proxy group. OCA M.B. at 75-76.

The OCA, as a remedy for Aqua's alleged failure to implement the commitments agreed to in the *Aqua-Peoples Settlement*, and for other areas in which the OCA contended were inadequate, requested:

> . . . that Aqua be held accountable for these previously agreed-to performance standards. OCA St. 6 at 23. [OCA witness Alexander] recommends that Aqua develop and submit a compliance plan to the stakeholders that, after review, should be submitted to the Commission for approval and implementation. *Id*. The plan should include specific action steps and deadlines for achieving compliance. *Id*.

OCA M.B. at 204.

Accordingly, the OCA reinforced its argument that there was no basis for awarding a rate of return higher than Aqua's estimated cost of equity. *See* OCA St. 3SR at 10.

As discussed, in detail, under Section X.D.2 of this Opinion and Order, Aqua requested an upward adjustment to its ROE for superior management performance. Aqua argued that in accordance with Section 523 of the Code, 66 Pa. C.S. § 523, the Commission is required to consider management effectiveness when setting rates. Aqua insisted that it has provided extensive evidence to demonstrate that it provides high quality service and has implemented numerous programs designed to enhance the service it provides to customers and that this evidence supports an addition to the allowed ROE. Aqua M.B. at 128-37.

b. Recommended Decision

As previously noted, the ALJ recommended that the Commission reject the Company's request for an upward adjustment to its ROE for superior management performance. R.D. at 79-81.

For different reasons, however, the ALJ was not persuaded that in rejecting the Company's request, the Commission should rely on the evidence proffered by the OCA and CAUSE-PA regarding the provision of poor customer service. In particular, the OCA argued for its persuasive evidentiary value, that a customer satisfaction survey indicated that 73% of Aqua customers with recent telephone call center transactions rated satisfaction as "excellent" or "very good." R.D. at 129 (referencing OCA St. 6 at 11; OCA M.B. at 191). The OCA argued that this level of customer satisfaction is low compared to Pennsylvania electric and gas companies where over 80% of customers typically express that they are "very satisfied" with their interaction with the utility's representative. R.D. at 120-30. In considering this testimony, the ALJ agreed with Aqua that its customer satisfaction survey indicating only 73% of customers rated their satisfaction as "excellent" or "very good" is not, in and of itself, indicative of poor customer service, particularly during the COVID-19 pandemic in which certain customer interactions have had to be limited. *Id*.

Accordingly, the ALJ recommended that in rejecting the Company's request for a management performance adjustment the Commission should instead rely on the findings the ALJ made on pages 79-81 of her Recommended Decision, discussed, *supra*.

c. OCA Exception No. 23 and Replies

In its Exception No. 23, the OCA argues that the ALJ properly recommended that the Commission reject Aqua's claim for an upward adjustment to its ROE for superior management performance. Nonetheless, the OCA submits that in recommending that the Commission reach this conclusion, the ALJ erred in finding that the Commission should not rely on the evidence proffered by the OCA and CAUSE-PA that demonstrates that the Company provides less than adequate customer service. The OCA points to the testimony of its witnesses Ms. Alexander and Mr. Colton that Aqua's call center performance level in comparison to other utilities was not a good indicator regarding Aqua's customer satisfaction. OCA Exc. at 34 (citing OCA St. 6 at 9-11; OCA St. 6SR at 5).

For purposes of ensuring that all of the evidence rebutting Aqua's claim for a management performance adder is reviewed, in addition to the evidence adopted by the ALJ, the OCA submits that Aqua's lower customer satisfaction level should be considered as one of many instances of Aqua's lack of evidence to support a management performance adjustment. Therefore, the OCA argues that the Commission should consider Aqua's poor satisfaction ratings, including the fact that Aqua's customer survey indicated that only 73% of customers rated their satisfaction as "excellent" or "very good" as further support for the OCA's recommended ROE and as additional support for rejecting the management performance adder. OCA Exc. at 34-35 (citing OCA St. 6 at 8-22).

In its Replies to Exceptions, the Company refers the Commission to its prior evidence and argument in support of a management performance adder, and discussed in Section X.D.2 of this Opinion and Order, *supra*. Aqua R. Exc. at 20.

In its Replies to Exceptions, I&E explains that although it did not file any testimony regarding the Company's customer service satisfaction levels, it does not oppose the OCA's assertions, as set forth in OCA Exception No. 23. I&E R. Exc. at 19.

d. Disposition

As set forth in our disposition of Section X.D.2, *supra,* we have determined that Aqua has exhibited extraordinary effort in aiding and protecting Pennsylvania water and wastewater customers and the environment. Thus, we have awarded the Company a management performance adjustment of twenty-five basis points to its ROE. For this reason, we shall decline to address the additional arguments of the OCA, as set forth in its Exception No. 23, for rejecting the Company's requested management performance adjustment. Accordingly, the OCA's Exception No. 23 is denied.

D. Masthope Allegations of Inadequate Wastewater Service

1. Positions of the Parties

Masthope contended that the Commission should deny Aqua's requested rate increase for Masthope's water and wastewater customers because the Company has provided unreasonable service. In this regard, Masthope alleged that there have been unreasonable systematic and unresolved instances of hydraulic overload conditions affecting the Masthope Wastewater Treatment Plant (WWTP) dating back to 2018, which resulted in restrictions upon Aqua's ability to make new wastewater connections. Masthope submitted that Aqua's insufficient planning, investment, maintenance, and operation solely caused the hydraulic overload conditions and ensuing building restrictions within Masthope. Masthope contended that any additional rate increase for Masthope's customers would be unjust and unreasonable given Aqua's failure to provide reasonable service over a period of years. Masthope M.B. at 9-24.

Aqua rebutted that it has adequately planned for the capacity needs of Masthope and has taken reasonable and appropriate measures to improve the wastewater system and service facilitates in its provision of service to the Masthope community. . The Company completed an evaluation of the capacity needs at the Masthope community as part of its 2018 Chapter 94 Report. Based on the evaluation, Aqua implemented the project known as the "Treatment Train Project" to address the system's increasing capacity needs and to avoid future hydraulic exceedance. Aqua St. 9-R at 36-37. Aqua asserted that based upon its evaluation of both the capacity and connection needs of the Masthope community, the Company's "Treatment Train Project," as expanded, would address both the system's need for increased capacity to prevent future hydraulic overload, as well as connection needs of the system. The Company noted that the Treatment Train Project was subsequently expanded to a long-term capital upgrade project based on an evaluation of the remaining connection needs of the system. The

Company also asserted it has demonstrated it is taking proactive steps to reduce inflow and infiltration (I&I) in the collection system as described in its 2020 Chapter 94 Report. Aqua M.B. at 195-200; Aqua R.B. at 84-89; Aqua St. 9-R at 36-37; Aqua St. 9-R at 37.

While maintaining it has taken affirmative steps, Aqua asserted that two events beyond its control led to hydraulic overloads on the system. The Company alleged that elevated precipitation levels and shifts to more full-time use of the residences at Masthope, because of the COVID-19 pandemic, caused hydraulic overloads on the system. As a result of the overloads, Aqua explained, PADEP issued a moratorium on new connections to the system. In response to the moratorium, Aqua submitted a Corrective Action Plan to PADEP, which was designed to restore or otherwise make available connection capacity at Masthope. At that time, the Company noted that the Corrective Action Plan was approved by PADEP, and consequently, PADEP also granted a sewer connection allocation of 60 Equivalent Dwelling Units (EDUs) to Aqua, which modified the prior total moratorium on sewer connections. *See* Aqua St. 9-R at 33-36; Aqua St. 9-R at 37; Aqua Post-Hearing Exh. 1.

2. Recommended Decision

As a procedural matter, the ALJ noted that the issues presented by Masthope were in the context of a complaint *against a utility's rate increase based on the unreasonable provision of service*, rather than a complaint based on the unreasonable provision of service. As such, the ALJ noted that the question was not:

> …whether Aqua's wastewater service to Masthope is adequate and reasonable given the persisting hydraulic overload conditions and resulting moratorium on new connections to the Masthope WWTP. Instead, the Commission must determine *whether Aqua's alleged failure to provide reasonable service is so pervasive that the Company should be punished for this failure by refusing to*

> *grant its request for increased revenue, and whether it is necessary and appropriate to direct service changes or the installation of additional facilities.*

R.D. at 133 (citing Masthope R.B. at 4 (quotations omitted, emphasis added)).

The ALJ noted the steps taken by Aqua to rectify the issues related to the Masthope system, including the Company's Treatment Train project, and the Company's Corrective Action Plan submitted to PADEP. Under the Corrective Action Plan, which was recently approved by the PADEP, the ALJ noted that the Company would restore and otherwise make connection capacity available for the Masthope community. *Id*. at 132.

The ALJ acknowledged "[t]he Masthope community is clearly experiencing challenges due to hydraulic overload at the WWTP." *See* R.D. at 133. However, the ALJ concluded that Aqua has taken affirmative steps to address the problem, and "[a]ppears to be working with PADEP to address the sewage planning and regulatory issues within that agency's purview."[149] Accordingly, the ALJ did not recommend that the Commission deny Aqua's request for a rate increase, decline to increase rates attributable to the cost of providing service to Masthope, or direct additional service changes or the installation of additional facilities. *Id*.

3. Masthope Exception No. 1 and Replies

In its Exception No. 1, Masthope challenges the grant of Aqua's requested rate increase based upon, *inter alia*, inadequate provision of service by Aqua where hydraulic overload conditions have persisted at the Masthope WWTP since at least 2018,

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[149] R.D. at 133. The ALJ also noted that Masthope may file an appeal to the Environmental Hearing Board if it believes that PADEP's response to the sewage planning issues are inadequate. *Id*. (citing, Aqua Post-Hearing Exh. 1).

and the resulting moratorium on new connections imposed by the PADEP in 2020, notwithstanding PADEP's recent modification to allow additional connections. Masthope remains of the opinion that a rate increase under these circumstances is unwarranted. Namely, Masthope emphasizes that the Masthope community experienced a substantial rate increase in 2019. Masthope Exc. at 4 (citing Masthope M.B. at 9-19; Masthope Exc. at 4-10).

Masthope asserts that the ALJ erred by: (1) failing to conclude that Aqua has rendered inadequate and unreasonable wastewater service; (2) concluding that the Commission lacks jurisdiction over the hydraulic overload issues facing the Masthope system; (3) making an unsubstantiated finding that increased precipitation levels and shifts from part-time to full-time residencies during the COVID-19 pandemic caused hydraulic overloads; and (4) failing to consider whether to impose conditions upon any rate increase granted in this proceeding. Masthope Exc. at 5-10.

Masthope reemphasizes its position that Aqua's requested rate increase is unjust and unreasonable for Masthope ratepayers, particularly since Masthope residents experience ongoing and unresolved service issues. Masthope notes that Aqua acknowledges that it may take five years to implement the plans to fully resolve the hydraulic overload conditions at the Masthope WWTP. Masthope Exc. at 4.

Masthope asserts the Commission has jurisdiction, pursuant to its authority under Section 523 of the Code, *supra,* to consider the adequacy of Aqua's service to Masthope customers in determining just and reasonable rates. Masthope argues that the Commission should find that Aqua failed to provide its Masthope customers with adequate, efficient, safe, and reasonable service and facilities, and therefore deny all or part of Aqua's requested rate increase. Masthope Exc. at 5-7 (citing, *e.g.*, *Sutter v. Clean Treatment Sewage Company*, Docket No. C-20078197, (Order entered May 15, 2009) (*Sutter*) at 14).

Masthope notes that while the ALJ acknowledged the Company's failure to provide adequate service, she should have recommended an adjustment to Aqua's requested rate increase to reduce the impact on Masthope wastewater customers. Masthope Exc. at 6-7 (citing R.D. at 29-30, Findings of Fact Nos. 11[2]-1[4][150]). Masthope also argues that it was error for the ALJ to conclude that because PADEP has granted limited approval of Aqua's proposed Corrective Action Plan, the Commission lacks jurisdiction to address those matters as part of the rate proceeding. Masthope Exc. at 6 (citing R.D. at 133). Masthope asserts that the Commission has previously drawn a distinction of PADEP jurisdiction over hydraulic overloads which involve strictly environmental protection issues and the Commission's jurisdiction over adequate service in the context of rate proceedings. Masthope Exc. at 6-7 (citing *Sutter*).

Next, Masthope argues that it was error for the ALJ to acknowledge any factors "beyond Aqua's control" as mitigating Aqua's responsibility for hydraulic overload conditions. Specifically, Masthope asserts that there is no evidence of record to support the impact of the COVID-19 pandemic, including shifts from part-time to full-time residency, and elevated precipitation levels as impacting hydraulic overloads. Masthope Exc. at 8-9 (citing R.D. at 132).

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[150] These Findings of Fact state, as follows:

> 112. Aqua submitted a Corrective Action Plan to Pennsylvania Department of Environmental Protection (PADEP), which is targeted at restoring or otherwise making available capacity to current and future connections at Masthope Mountain community.
> 113. This Corrective Action Plan was recently approved by PADEP.
> 114. As part of the approved Corrective Action Plan, PADEP also granted a sewer connection allocation of 60 Equivalent Dwelling Units (EDUs) to Aqua, modifying the sewer connection moratorium.

R.D. at 29-30 (citations omitted).

Finally, Masthope asserts that it was error for the ALJ to fail to impose any conditions on Aqua's proposed rate increase to assure the future provision of adequate and reasonable wastewater service for Aqua's Masthope customers, consistent with the Commission's authority to deny a rate increase *in part* where the Commission finds a public utility fails to render adequate service. Masthope Exc. at 9 (citing Masthope M.B. at 9-19; Masthope R.B. at 2-5).

Masthope requests that, if the Commission approves an increase in Masthope rates, the Commission should impose conditions and deadlines on Aqua to assure that the Company timely resolves the hydraulic overload conditions and permanently eliminates building restrictions that detrimentally affect the community. Further, Masthope argues the existence of Aqua's Corrective Action Plan in response to the PADEP does not preclude the Commission's authority to impose further such conditions. Masthope Exc. at 2, 6.

Specifically, Masthope requests that the Commission impose conditions to resolve the hydraulic overload conditions and eliminate building restrictions by directing Aqua to:

- coordinate with Masthope and local officials regarding the Corrective Action Plan;

- report to Masthope and the Commission on the status of corrective actions;

- seek additional requests or an amendment to the Corrective Action Plan to increase the number of connections to the Masthope WWTP pending completion of the Corrective Action Plan;

- assure that Aqua's "Project 15088006258 – Masthope WWTP Add Treatment Train" results in eliminating the building restrictions currently affecting the Masthope WWTP;

- timely complete Act 537 planning and related improvements to eliminate building restrictions in Masthope; and

- at a minimum, in light of PADEP's recent modifications to Aqua's Corrective Action Plan, require that Aqua meet and confer with Masthope and Lackawaxen Township officials to discuss the 60 permitted connections to determine areas of priority and maximize the benefit to the Masthope community.

Masthope Exc. at 9 (citing Masthope M.B. at 9-19; Masthope R.B.at 2-5).

Accordingly, Masthope asserts that the Commission should reject the ALJ's recommendation, grant Masthope's Exception No. 1, impose a reasonable reduction in Aqua's requested rate increase as it pertains to the Masthope community, and otherwise impose reasonable conditions upon Aqua to ensure timely resolution of the hydraulic overload conditions and elimination of building restrictions. Masthope Exc. at 10.

In its replies, Aqua asserts that the ALJ properly recommended that the Commission deny Masthope's claims of poor quality of service as a basis for challenging the Company's requested rate increase. Aqua notes that the ALJ correctly concluded that Aqua has taken affirmative steps to resolve problems facing this system, and proactively identify improvements to address "sewage planning and regulatory issues within…[PADEP's] purview." Aqua asserts that its affirmative steps taken to improve the system, which led to PADEP's lifting of the ban on new housing in Masthope, based upon Aqua's detailed Treatment Train Project, as expanded to a long-term capital upgrade project, and other steps taken by the Company to reduce I&I in the collection system, demonstrate Aqua's reasonable provision of service in the circumstances. Aqua R. Exc. at 23-25 (citing R.D. at 133; Aqua M.B. at 195-96). Aqua concludes that, as found by the ALJ, Aqua has provided reasonable service and taken reasonable steps to address the problems facing this system. Aqua R. Exc. at 25.

Aqua further asserts that Masthope misconstrues the Commission's decision in *Sutter*, which Aqua asserts is distinguishable from the present circumstances. Specifically, Aqua claims that, unlike the utility in *Sutter*, Aqua has taken prompt and significant steps to resolve the hydraulic overloads facing the Masthope system, including the recently approved Corrective Action Plan submitted to PADEP. Aqua Exc. at 24 (citing Aqua R.B. at 85-86).

Aqua asserts that, contrary to Masthope's position, the record fully supports the ALJ's conclusion regarding the impact of circumstances beyond Aqua's control upon the occurrence of hydraulic overloads, including increased precipitation levels and shifts from part-time to full-time residencies during the COVID-19 pandemic. More specifically, Aqua notes that its witness, Mr. Duerr, testified to the steps taken by Aqua beginning in 2018 to address the system's issues, and the intervening events in 2020 that resulted in these overloads. Aqua Exc. at 24-25 (citing Aqua M.B. at 196-97).

Finally, Aqua contends that the Commission should reject Masthope's request that the Commission condition Aqua's requested rate increase. Aqua asserts that Masthope's proposed conditions relate to items identified in Aqua's Chapter 94 Reports and the Corrective Action Plan which was approved under the purview of the PADEP. Aqua Exc. at 25 (citing Aqua R.B. at 87-88).

Accordingly, Aqua asserts that the Commission should deny Masthope's Exception No. 1 and adopt the ALJ's recommendation dismissing Masthope's Complaints at Docket Nos. C-2021-3028992 and C-2021-3028996. Aqua Exc. at 25.

In its replies, I&E asserts its support for what it describes as the ALJ's well-reasoned recommendation as it pertains to Masthope. I&E R. Exc. at 24.

Finally, in its Replies, the OCA asserts that if the Commission grants Masthope's request to reduce the rate increase for Masthope customers, the remedy should not shift or impose corresponding costs on other Aqua water or wastewater customers. The OCA asserts that the revenue requirement associated with the rates set for Masthope should not be reallocated to other Aqua customers, based on Masthope's claim of inadequate service. Rather, if inadequate service is found, the OCA maintains that Aqua should bear the cost by reduction in the return on equity because the revenue requirement for Masthope would not be fully reflected in rates. OCA R. Exc. at 18 (citing OCA R.B. at 50; Masthope Exc. at 4-10).

4. Disposition

Upon review, as discussed more fully, *infra.*, we agree with the ALJ's recommendation to grant Aqua's proposed rate increase as applicable to Masthope, and we decline to impose any additional conditions upon Aqua related to the reduction of hydraulic overload conditions and elimination of building restrictions.

As a preliminary matter, we agree with the ALJ that our disposition of this issue turns on whether Aqua's alleged failure to provide reasonable service is so pervasive that the Company should be punished for this failure by refusing to grant its request for increased revenue, and whether it is necessary and appropriate to direct service changes or the installation of additional facilities.

Further, we agree with the general principles argued by Masthope that it is within the Commission's discretion pursuant to our authority under Section 523 of the Code, to consider the adequacy of Aqua's service to Masthope customers in determining just and reasonable rates. Should we determine that Aqua's provision of service was inadequate *in the circumstances*, it is within our discretion to deny or reduce Aqua's requested rate increase, and/or impose further conditions as deemed reasonable and necessary in the circumstances. However, under the circumstances, we do not conclude that Aqua's provision of service to Masthope may be found to be unreasonable, or so inadequate as to justify a reduction in the proposed rate increase or warrant imposition of additional conditions upon Aqua's provision of service.

In the present circumstances, it is acknowledged that the Masthope community has experienced serious customer service issues regarding hydraulic overloads and the inability to meet the needs for new connections. However, in the context of a requested rate increase, our recognition of the serious allegation of issues regarding the provision of service must also include consideration of the Company's response to those issues. Where the Company's response is untimely and/or inadequate, we may be persuaded that the Company's proposed rate increase should be denied in total or reduced by some measure, and/or that certain conditions should be attached to the rate increase approval. *See Sutter, supra*.

Here, however, we conclude that the facts of the present case reflect that Aqua has taken prompt, reasonable and affirmative steps to rectify the problems associated with hydraulic overloads and the connection needs of the Masthope community. As noted by the Company, Aqua's detailed Treatment Train Project, as expanded to a long-term capital upgrade project, and other steps taken by Aqua to reduce I&I in the collection system, demonstrate Aqua's reasonable provision of service in the circumstances. Aqua R. Exc. at 23-25 (citing, R.D. at 133; Aqua M.B. at 195-96).

Further, we disagree with Masthope's argument that the Commission's prior decision in *Sutter* is applicable in the present circumstances. We note that *Sutter* is an example of the exercise of the Commission's discretion on a case-by-case basis, in the circumstances involving a rate increase which did not establish a mandatory standard or ruling. Although *Sutter* did involve the Commission's exercise of jurisdiction where a utility had matters pending before the PADEP, the facts in *Sutter* are distinguishable in material respect to the facts presently before us. Foremost, the utility in *Sutter* did not demonstrate the prompt and affirmative steps to rectify the service deficiencies at issue in the proceeding. *See*, generally, *Sutter,* at 14. . In contrast here, the record reflects Aqua's prompt, reasonable and affirmative steps to rectify the problems and needs of the Masthope community.

Accordingly, we shall deny Masthope's Exceptions No. 1, and adopt the ALJ's recommendation, dismissing the Complaints at Docket Nos. C-2021-3028992 and C-2021-3028996.

E. COVID-19 Uncollectible Deferral

1. Positions of the Parties

Rather than requesting recovery of its existing COVID-19 deferral amounts in this current rate case, Aqua proposed to continue recording amounts in its COVID-19 deferral account and to seek recovery in a future rate case. In support, Aqua explained that the Commission previously authorized utilities to create regulatory assets for incremental uncollectible expenses related to COVID-19 above those already embedded in base rates. Aqua M.B. at 200 (citing Aqua St. 1 at 22-24).

Aqua noted increased levels of unpaid billings or "bad debt," due to the service termination moratorium, citing *Public Utility Service Termination Moratorium Proclamation of Disaster Emergency – COVID-19*, Docket No. M-2020-3019244 (Emergency Order ratified March 26, 2020) (*Emergency Order*). According to Aqua, this increased the Company's uncollectible accounts expense above the amount currently embedded in its base rates, which were $2,425,823 for water and $217,335 for wastewater base systems during the HTY. Aqua explained that it calculated these expenses by normalizing them to pre-pandemic levels, specifically the rate of bad debt expense implicitly authorized in the *Aqua 2018 Rate Case*. The Company recorded a regulatory asset of $5,695,030 as a result of aging accounts receivable from its customers due to the termination moratorium. Aqua M.B. at 201.

Aqua argued that, although the service termination moratorium has ended, Pennsylvania continued to be impacted by the COVID-19 pandemic at the time of the Company's filing, and that it continues to incur incremental levels of uncollectible expenses beyond the end of the HTY. In response, Aqua sought continued authorization to defer (not recover) these incremental expenses realized over and above its recovery levels for review and recovery in its next base rate case. Aqua M.B. at 201-02 (citing Aqua St. 1 at 23-24).

Aqua asserted that it was not asking for "any time value of the money related to these deferrals" and that the Company and its shareholders were currently funding, and will continue to fund, the delayed cash inflow from aging accounts receivable. Thus, the Company submitted that its customers will not fund this aspect of the incremental costs Aqua has incurred to provide continuous and reliable service in the face of a global pandemic. Aqua M.B. at 203 (citing Aqua St. 1-R at 7).

Moreover, the Company asserted that it has not sought authorization to defer any incremental expenses for safety supplies, masks, hand sanitizers, social distancing signage, which were required in many facilities. According to the Company, Aqua has been and will continue to be conservative in seeking to recover incremental COVID-19 related expense. Aqua M.B. at 203-04.

I&E recommended the Company be required to track further COVID-19 related reductions to uncollectible expenses in its water and individual wastewater revenue requirements; and, that the balances be claimed in the next rate filing, which is anticipated to be filed in 2024. Further, I&E requested that Aqua: (1) be required to propose amortization of the balance at that time, amortized over a period of years, to be claimed in the next rate proceeding; and (2) be allowed to claim no interest or any time value of money component associated with the delay. Also, I&E recommended that the Company be allowed to claim no increases to COVID-19 related uncollectible expenses beyond the effective date of new rates in this proceeding, because Aqua has expressed that its motivation in delaying the amortization of the balance is to mitigate the impact on ratepayers. I&E M.B. at 58-59.

I&E added that any new increases to the COVID-19 related uncollectible expenses should not be recoverable in a future proceeding. According to I&E, the recommended delay is based on Aqua's assertion that the COVID-19 related uncollectible expenses are declining since the Company has been permitted to resume collection activities, and that the Company expects this declining trend to continue which would reduce the impact on ratepayers. I&E submitted that any new increases to the COVID-19 related uncollectible expenses should not be recoverable in a future proceeding. I&E M.B. at 57, 59.

The OCA recommended that Aqua offset any claimed costs with savings that it has recognized during the pandemic. Aqua agreed with this recommendation. However, the OCA contended that indefinite continued deferrals beyond the FPFTY would be unreasonable and should not be permitted. According to the OCA, the end of the FPFTY would be a reasonable point to cut off the Company's ability to continue recording incremental deferred uncollectible expenses related to the pandemic. OCA M.B. at 50.

2. Recommended Decision

The ALJ recommended that the Commission should continue to authorize Aqua to defer its COVID-19 related uncollectible expenses. However, the ALJ agreed with I&E that Aqua should be required to track further COVID-19 related reductions to uncollectible expenses pursuant to its water and the individual wastewater revenue requirements. The ALJ reasoned that the burden is on Aqua to demonstrate that these expenses are "prudently incurred incremental extraordinary, nonrecurring expenses related to COVID-19." R.D. at 136 (citing Secretarial Letter issued by the Commission on May 13, 2020, at Docket No. M-2020-3019775 titled "COVID-19 Cost Tracking and Creation of Regulatory Asset" (*May 2020 Secretarial Letter*)).[151] Agreeing with the OCA, the ALJ also stated that these expenses should be offset by any savings, upon which Aqua indicated agreement. R.D. at 136.

Additionally, the ALJ emphasized that, to date, the Commission has declined to impose a hard cutoff for the accumulation of deferred expenses related to COVID-19. The ALJ noted the provisions of the *May 2020 Secretarial Letter* have not been modified and cited to a recent decision of the Commission indicating that the effects

[151] Subsequent to the *May 2020 Secretarial Letter*, the Commission issued the following Orders: *Public Utility Service Termination Moratorium – Modification of March 13th Emergency Order*, Docket No. M-2020-3019244 (Order entered October 13, 2020) (*October 2020 Order*); *Public Utility Service Termination Moratorium*, Docket No. M-2020-3019244 (Order entered March 18, 2021) (*March 2021 Order*); and *Public Utility Service Termination Moratorium; COVID-19 Cost Tracking and Creation of Regulatory Asset*; Docket Nos. M-2020-3019244 and M-2020-3019775 (Order entered July 15, 2021) (*July 2021 Order*).

of the COVID-19 pandemic are still being felt by utilities.[152] Therefore, the ALJ deemed it premature to establish a hard cut-off date for the accumulation of deferred expenses and savings in this base rate proceeding. Rather, the ALJ was persuaded by Aqua's argument that permitting additional time for economic conditions to stabilize will not harm ratepayers and may perhaps be to their benefit as the Company is able to offset uncollectible expenses with increased collection activities. R.D. at 136 (citing Aqua St. 1-R at 7).

The ALJ acknowledged the Company's contention that it is not seeking any time value of the money related to these deferrals, nor is it seeking authorization to defer any incremental expenses for safety supplies, masks, hand sanitizers, and social distancing signage, that were required in many facilities. The ALJ further reasoned that uncollectible expenses may be mitigated by the enhancements to Aqua's universal service program and from recent federal funding dedicated to reducing unpaid utility bills. R.D. at 136-37.

3. OCA Exception No. 7 and Replies

In its Exception No. 7, the OCA argues that the ALJ erred in accepting Aqua's proposal to continue deferring its COVID-19 uncollectible expenses indefinitely. OCA Exc. at 9-10.

The OCA begins with its agreement that the pandemic is ongoing and its continuing impacts have informed the OCA's other adjustments including those

[152] *See Petition of Pennsylvania-American Water Company for Authorization to Defer, and Record as Regulatory Assets for Future Recovery: (1) Incremental Expenses Incurred Because of the Effects of the COVID-19 Emergency; (2) Revenue Reductions Attributable to the Effects of the COVID-19 Emergency; and (3) Carrying Charges on the Amounts Deferred*, Docket No. P-2020-3022426 (Order entered September 15, 2021) (*PAWC COVID-19 Deferral Order*).

regarding seasonal positions and rate case expense, citing the OCA Exception Nos. 4 and 5. Despite this, the OCA asserts it is unreasonable to continue to allow deferrals indefinitely beyond the FPFTY. OCA Exc. at 9 (citing OCA St. 1 at 63). According to the OCA, the Commission should establish a clear point in time during which Aqua must cease recording costs related to COVID-19 into the existing deferral account, in order to ensure that those costs do not accumulate to unreasonably burden consumers in later rate cases. OCA Exc. 9-10.

The OCA submits that the end of the FPFTY would be a reasonable point to end the current deferral and the Commission should impose such a cut-off for the Company. The OCA adds that if the Company finds it necessary to continue to defer COVID-19 related costs at the end of its FPFTY (*i.e.*, by March 31, 2023), it can ask the Commission to approve a new deferral mechanism at that time. *Id*. at 10.

In its reply, Aqua argues that the ALJ correctly rejected the OCA's arguments. The Company asserts that the OCA still believes it necessary to set an end-date for the calculation of COVID-19 deferrals that increase expenses but wants to capture any future decreases to the balance. Aqua submits that the OCA's approach is unbalanced and should be rejected. The Company contends that its proposal, as modified and adopted by the ALJ, is balanced because it continues to defer the determination of changes to the COVID-19 uncollectible accounts balance, whether higher or lower, until Aqua's next rate case. Aqua R. Exc. at 6.

Emphasizing the ALJ's reference to the *May 2020 Secretarial Letter* and that the Commission has declined to impose a hard cut-off for the accumulation of deferred expenses related to COVID-19, the Company argues that establishing a cut-off date only for Aqua in the context of this rate proceeding would be unfair and premature. Accordingly, Aqua contends that the OCA's Exception No. 7 should be denied. Aqua R. Exc. at 7 (citing Aqua M.B. at 200-06; Aqua R.B. at 89).

In its reply to the OCA's Exception No. 7, I&E asserts that it does not oppose the OCA's argument that the ALJ erred in accepting Aqua's proposal to continue deferring its COVID-19 uncollectible expenses indefinitely. I&E also references the ALJ's conclusion that the Commission has declined to impose a hard cut-off date for the accumulation of such deferred expenses. However, I&E recommends that, until such time as a hard cut-off date is established, the Commission in this proceeding should set the cut-off date for Aqua at the effective date of new rates. I&E R. Exc. at 14-15.

4. Disposition

Aqua seeks Commission approval of its request to continue recording amounts in its COVID-19 deferral account and to seek recovery in a future rate case. As discussed in *PAWC COVID-19 Deferral Order*, the Company must demonstrate that the expense items it requests to defer appear to be within the scope of the type of items that the Commission has allowed as an exception to the general rule against retroactive recovery of past expenses. Commission authorization for deferral accounting is not intended to create a factual record. As such, the burden of proof will remain with Aqua in a future proceeding to demonstrate that each expense item is: (1) extraordinary and substantial, (2) nonrecurring, (3) incremental and, (4) COVID-19 related consistent with the *May 2020 Secretarial Letter*. *See PAWC COVID-19 Deferral Order* at 6-7.

Regarding COVID-19 cost tracking and the creation of regulatory assets, the Commission directed regulated utilities in Pennsylvania:

> [T]o track extraordinary, nonrecurring incremental COVID-19-related expenses and to maintain detailed accounting records of such expenses. Utilities must maintain detailed records of the incremental expenses incurred for the provisioning of utility services used to maintain the health, safety and welfare of Pennsylvania customers during the COVID-19 pandemic. With the exception of the separate

> regulatory authorization afforded uncollectible expenses below, this Secretarial Letter does not grant authorization for utilities to defer any other potential COVID-19-related expenses.

May 2020 Secretarial Letter at 2.

The directives in the *May 2020 Secretarial Letter* were reaffirmed in our *July 2021 Order*, as follows:

> The Commission acknowledged in its [*March 2021 Order*] that its COVID-19 related Orders may benefit customers and increase expenses for utilities. Consistent with our May 13, 2020, Secretarial letter at Docket No. M-2020-3019775, the Commission hereby confirms that utilities shall continue tracking extraordinary, nonrecurring incremental COVID-19 related expenses and shall maintain detailed accounting records of such expenses. Additionally, the Commission hereby confirms that electric, natural gas, water, wastewater, steam, and all rate base/rate of return telecommunications utilities are authorized to create a regulatory asset for any incremental expenses incurred above those embedded in rates resulting from the directives contained in this Order. To be eligible for inclusion in a utility's COVID-19 designated regulatory asset, the utility must maintain detailed records of the incremental extraordinary, nonrecurring expenses incurred as a result of compliance with the Commission's [*Emergency Order*, *March 2021 Order*, *October 2020 Order*] and this Order.

July 2021 Order at 4.

Here, there is no dispute that the incremental uncollectible expenses related to COVID-19 above those already embedded in base rates are within the scope of the type of items which are allowable as an exception to the general rule against retroactive recovery of past expenses. Aqua has elected to defer seeking recovery of these expenses until its next base rate proceeding at which time it will have the burden of proof to demonstrate that each expense satisfies the Commission standards for recovery.

The only question in this proceeding is whether the Commission should impose a cut-off date for the accumulation of deferred expenses related to COVID-19. Aqua seeks to extend the accumulation period until its next base rate proceeding. I&E requests that the Commission stop the accumulation time period beginning with the effective date of new rates established in this proceeding. The OCA proposes a continuation of the deferral of COVID-19 related costs until the end of the Company's FPFTY in this proceeding and thus by March 31, 2023.

Consistent with our determination in *PAWC COVID-19 Deferral Order*, we shall decline to set a hard cut-off date for the accumulation of deferred expenses. It is evident that the effects of COVID-19 are still being felt by utilities and we deem it premature to conclude that the pandemic is over and that no additional related expenses will be incurred beyond the end-dates proposed by I&E and the OCA.

We also agree with the well-reasoned conclusions of the ALJ that permitting additional time for economic conditions to stabilize will not harm ratepayers but may operate to their benefit if the Company is able to offset uncollectible expenses with increased collection activities. *See* Aqua St. 1-R at 7. Further, Aqua provided testimony that it is not seeking the time value of the money related to these deferrals, nor is it seeking authorization to defer any incremental expenses for safety supplies, masks, hand sanitizers, or social distancing signage, that were required in many facilities. *Id*. Moreover, as noted by the ALJ, uncollectible expenses may be further mitigated by the enhancements to the Company's universal service program and from recent federal funding dedicated to reducing unpaid utility bills. *See* R.D. at 137.

In declining to establish a cut-off date for the accumulation of deferred expenses in this proceeding, we emphasize that consideration of the period of recovery for any regulatory asset treatment is being deferred to the subsequent base rate proceeding filed by the Company. Again, such deferred amounts that Aqua may seek to recover in a future proceeding will be subject to detailed review and investigation and the burden of proof will remain with the Company to establish the prudence and reasonableness of its incremental COVID-19 related financial impacts.

Thus, we shall deny the OCA's Exception No. 7 and adopt the recommendation of the ALJ.

F. Directed Questions of Commissioner Yanora

On September 16, 2021, Commissioner Yanora requested that the Parties address certain issues, including questions pertaining to lead service lines, cross-connections, backflow prevention devices, and lost and unaccounted for water. The Company provided responses to these questions in Aqua Exhibit TMD-4-R which were sponsored by Aqua's witness, Mr. Duerr, with his rebuttal testimony. *See* Aqua M.B. at App. D.

The specific inquiries are as follows:

1) The estimated number of company-owned lead service lines and the number of customer-owned lead service lines in the Aqua water distribution system;

2) Compliance of the Aqua tariff cross-connection control requirements with 25 Pa. Code §§ 109.709, 109.609 and any applicable provisions of the International Plumbing Code;

3) Compliance materials of Aqua's operation and maintenance plans required by 25 Pa. Code § 109.702 as they relate to

adequate, safe, and reasonable service for utility customers and employees;

4) The number of Aqua's commercial meters in the system, the number tested, and the number passed or failed for calendar year 2020;

5) The number of Aqua's valves exercised in calendar year 2020 and the frequency of valve maintenance;

6) The number of Aqua's commercial and industrial customers that have testable backflow prevention devices and the number of devices that were tested for calendar year 2020;
7) Aqua's tariff backflow prevention requirements regarding residential fire protection and irrigation and whether Aqua has a plan for inspection and testing of fire hydrants;

8) Whether Aqua has surveyed the number of fire hydrants that do not provide a minimum flow of 500 gallons per minute at 20 pounds per square inch; and

9) Whether Aqua's residential customers have American Society of Sanitary Engineers 1024 backflow assemblies installed at meter locations.

10) Whether Aqua has evaluated its lost and unaccounted water performances since 2018 and any relevant results.

Directed Questions at 1-2.

The following discussion provides a summary of the responses provided by Aqua's witness, Mr. Duerr, in addressing the Directed Questions. Aqua Exh. TMD-4-R.[153] We note that some of the areas of inquiry have already been addressed in the Quality of Service sections, *supra*.

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[153] There are no page numbers within this exhibit; thus, we shall follow the Company's general citation method to the questions and responses (*i.e.*, Yanora-1, Yanora-2, *etc.*).

Regarding the first inquiry about the estimated number of lead service lines in Aqua's system, the Company responded that on September 3, 2020, Aqua filed a petition for approval of tariff changes authorizing the replacement of customer-owned lead service lines. Aqua asserted that the Commission approved the petition on July 15, 2021, pursuant to a modified settlement.[154] The Company submitted that since receiving approval it has reached out to customers with known lead service lines and is in the process of getting agreements in place with customers to allow replacement of their lead service line under Aqua PA's program. Yanora-1.

The Company added that, as of September 2021, Aqua had seven known Company-side lead service lines and identified 325 customer-owned lead service lines in its system based on the review of tap cards, water sampling data, meter exchange, and service call information. Aqua estimated that in total there are over 100 Company-side lead service lines and over 2,000 customer-owned lead service lines. *Id*.

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[154] On May 28, 2021, ALJ Marta Guhl granted Aqua's modified Joint Petition for Settlement and approved the Company's Joint Settlement Replacement Plan set forth in the Settlement. *See Petition of Aqua Pennsylvania, Inc. for Tariff Changes Authorizing Replacement of Customer-Owned Lead Service Lines*, Docket No. P-2020-3021766 (Recommended Decision issued May 28, 2021). No Exceptions to the Recommended Decision were filed and the Commission entered a Final Order adopting the Recommended Decision on July 15, 2021 (*Aqua LSL Order*).

As to the second inquiry concerning compliance with tariff cross-connection[155] control requirements, Aqua asserted that it has an established cross-connection control program operated under its Cross-Connection Control Manual (Manual). The Company attached a copy of the Manual (as Yanora-2, Attachment 1) and indicated that as of July 2021, 77% of known backflow devices in Aqua's service areas were tested in accordance with 25 Pa. Code §§ 109.709, 109.608 and applicable provisions of the International Plumbing Code. According to Aqua, all new customers of its systems are required to install backflow devices as identified in the standards and specification outlined in its Manual which meet the requirements of the codes noted above. Yanora-2.

Regarding the third inquiry, Aqua submitted that it has an operation and maintenance plan required by 25 Pa. Code §109.702 as it relates to adequate, safe, and reasonable service for utility customers and employees. The Company stated that this plan was last updated in November 2019 and will be updated again in 2022 after the Company completes its requirements to update emergency response plans required by the American Water Infrastructure Act, which the Company indicated were due on December 31, 2021, for certification of Group 3 systems. In addition to general updates,

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[155] Cross connections are defined in the PA DEP's regulations as follows:

> Cross-connection—An arrangement allowing either a direct or indirect connection through which backflow, including backsiphonage, can occur between the drinking water in a public water system and a system containing a source or potential source of contamination, or allowing treated water to be removed from any public water system, used for any purpose or routed through any device or pipes outside the public water system, and returned to the public water system. The term does not include connections to devices totally within the control of one or more public water systems and connections between water mains.

25 Pa. Code § 109.1.

Aqua stated that the updated operation and maintenance plan will reflect acquired systems and updates related to other operating plans. Yanora-3.

Regarding the fourth inquiry concerning the number of commercial meters in the system, the number tested, and the number passed or failed for 2020, Aqua responded that at the end of 2020, the Company had 23,139 meters installed at commercial premises within the service area. Aqua added that in 2020, 801 meters installed at commercial premises were removed and tested; 458 (57%) of those meters failed their testing based on flowrates and accuracy defined by the standards of the American National Standards Institute (ANSI) and the AWWA for new meters. Yanora-4 (citing ANSI/AWWA C-700).

The fifth inquiry concerned the number of valves exercised in calendar year 2020 and the frequency of valve maintenance.[156] Aqua responded that it has a critical valve testing program that was reviewed during the Commission's recent Management Audit report. In this report, Aqua noted that it has been credited with developing a strong base for its valve inspection program by focusing on critical valves. Yanora-5.

Additionally, Aqua referenced the Management Audit recommendation that Aqua implement a full-scale valve inspection and exercise program designed to identify what valves have not been operated or inspected in the last ten years. Although Aqua

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[156] Generally, the exercising of a water main valve means that each valve connected to the water main of the distribution system is tested to ensure it is working properly by operating the valve through a full cycle and returning it to its normal position (*i.e.*, turning the valve completely off, then gradually opening it and closing it, before returning it to its normal open position). *See e.g.*, Zane Satterfield, P. E., *Tech Brief – Valve Exercising*, Summer 2007, Vol. 7, Issue 2, National Environmental Services Center; https://www.nesc.wvu.edu/files/d/1f62b334-8497-403e-bceb-f5116ac2c142/valve-exercising.pdf.

agreed that non-critical valve inspection and exercising program is warranted, it had concerns with the suggested exercising frequency outlined in the report. As part of the implementation plan, Aqua agreed to engage a consultant to evaluate the Company's water systems and develop a non-critical valve inspection and exercising program. According to Aqua, this effort will consider such factors as standard operating procedures for inspection and exercising valves, valve operating frequency, the identification of routinely operated valves, and the resources necessary to complete these procedures. Aqua asserted that this program will ensure that non-critical valves will be inspected and exercised on a level representing good industry practice. The Company added that the exercising frequency will be included in the review by the consultant and Aqua will provide the recommended frequency in its next update report. *Id*.

In further response to the fifth inquiry, Aqua explained that all critical valves have been identified in the Aqua Geographic Information System (GIS) asset registry and will continue to be updated as as-builts are received. These valves currently have exercising schedules created and maintained in Aqua's work order management system or Maintenance Connection. The Company indicated that these schedules will be transferred to SAP Plant Maintenance in January 2022 and maintained at the asset level to ensure compliance with critical valve requirements. Aqua also asserted that all non-critical valves have been identified in the Aqua GIS asset registry. The Company conducted an analysis to ensure the exercising of these valves is completed over a 12-year period. According to Aqua, internal staff used GIS analysis techniques to identify valve proximity to major roadways to determine staffing requirements needed for traffic control measures. The Company stated that operation staff are meeting to determine which non-critical valves are scheduled per year. *Id*.

Additionally, Aqua stated that 129 isolation valves were repaired during calendar year 2020. Although the Company does not at present have a program for operating valves based on frequency, Aqua noted its operation of approximately 6,000 to

8,000 valves during its normal course of business which it estimated as ten percent of the valves in service each year. Aqua stated that the program operates critical valves at least once every four years and there are 270 valves in the program which began in 2017. The Company emphasized the ongoing nature of the program and the potential for occasional changes depending on modifications made in the distribution system. For reference, Aqua asserted that as of October 2021 there were a total of 83,547 valves in its system and provided a breakdown by region. *Id.*[157]

In response to the sixth inquiry, Aqua provided information related to the number of commercial and industrial customers that have testable backflow prevention devices and the number of devices that were tested for calendar year 2020. The Company stated that there are 21,830 testable backflow devices installed on commercial premises, and 920 testable backflow devices installed on industrial premises. In 2020, Aqua recorded passable tests for 15,573 devices installed on commercial premises and 643 devices installed on industrial premises. Yanora-6.

The seventh inquiry pertained to tariff backflow prevention requirements regarding residential fire protection and irrigation and whether Aqua has a plan for inspection and testing of fire hydrants. In response, Aqua cited to the Manual provided in response to the second inquiry, which defines the requirements for residential fire protection and irrigation accounts. According to the Company, all new residential fire protection and irrigation services are required to install testable backflow devices and those devices are required to be tested annually. Yanora-7.

In response to the eighth inquiry – whether Aqua has surveyed the number of fire hydrants that do not provide a minimum flow of 500 gpm at 20 psi – Aqua replied

[157] PA-Southeastern comprised the largest number of valves at 66,033. The remainder of the regions were as follows: PA-Central – 5,374; PA-Northeastern – 6,322; and PA-Western – 5,818. Yanora-5.

that it has approximately 24,500 hydrants in service in Pennsylvania. During its normal course of business, Aqua continued, it receives requests to perform flow testing from various groups outside the Company such as fire companies, sprinkler contractors, township engineers and insurance companies. Aqua also noted it performs flow tests for its own internal purposes to review fire flow in areas of its systems, with 300-500 flow tests performed annually. According to Aqua, all tests assist in decisions in operating the system and for capital planning and tests coming back with less than 500 gpm at 20 psi residual are reviewed more thoroughly. If the hydrant is in good working order and does not need repairs, Aqua explained, the hydrant location area is passed along to the Engineering Department in order for the area to be included as a candidate within Aqua's Main Replacement program. Yanora-8.

Additionally, the Company stated that as a follow up from the last rate case, it provided information regarding all fire hydrants connected to 4-inch mains or smaller that are not capable of providing 500 gpm of water at 20 psi. *Id.*[158]

The ninth inquiry concerns whether Aqua has determined if its residential customers have American Society of Sanitary Engineers (ASSE) 1024 backflow assemblies installed at meter locations. Aqua replied that its Rules and Regulations require all new customer connections to the Company's distribution system be equipped with backflow prevention, cross-connection-control or other special devices approved by the Company and in accordance with the Company's specifications. Further, at the Company's request, existing customers must install backflow prevention, cross-connection-control or other special devices approved by the Company to existing customer connections which must comply with the Company's specifications. Yanora-9.

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[158] Aqua designated this information as Confidential and submitted it pursuant to the Protective Order issued in this proceeding. Yanora-8.

In support, Aqua submitted its Meter Installation Specifications, revised June 2015, indicating that it defines the requirements for all residential accounts. *See* Yanora-9, Attachment 1. The Company contended that all residential services are required to install an ASSE 1024 backflow device. Aqua asserted that these installations are monitored throughout its new business activities and the device is confirmed as installed before the meter is set. According to the Company, existing residential services are required to meet this standard when improvements are made to those properties requiring plumbing permits due to renovations and retrofits. Yanora-9.

In response to the tenth and final inquiry, Aqua affirmed that it has evaluated lost and unaccounted for water performance since 2018. The Company also emphasized that the Commission's Bureau of Audits recently reviewed this information in Aqua's 2020 Management Audit. Yanora-10.

Aqua explained that a yearly audit is conducted using the AWWA water audit tool which it described as "Version 6.0." *Id*. Aqua submitted that its performance exceeds industry medians for most key performance indexes, noting how Aqua's non-revenue water has held steady since 2018 at 20.2%, plus or minus 0.01%. The Company contended this results in a Real-Loss-Cost-Rate of only $6.39/connection/year which is below the median 30th percentile. *Id*.

As background, Aqua described the leak survey activity conducted in Southeast Pennsylvania by its three full-time leak survey technicians with one in each operating division office. The Company stated that its leak survey technicians normally perform leak surveys fifty-two weeks a year by pipe plate, which systematically performs a survey on the entire system. According to Aqua, the survey focuses on high-risk materials such as cast iron and stove pipe cement pipe and the objective is to survey 100% of the high-risk pipe in the system over a 15-month period. Aqua further described how leak survey technicians are available at any time to assist crews having trouble locating leak sources in the system. Additionally, Aqua noted that leak surveys are performed daily as the Company inspects hydrants, performs meter change outs, or responds to service calls. Specifically, the Company explained that the technician listens on the lines for leaks and any suspected leaks are relayed to maintenance personnel, who then respond. *Id*.

Next, the Company described its contract with Utilis, a remote-sensing data company, to conduct a pilot study survey of select distribution systems in 2019 in Southeast Pennsylvania. Aqua asserted that Utilis uses synthetic aperture radar satellite data along with their proprietary algorithm to specifically identify areas with soil moisture at a depth underground that often signifies drinking water leaks from pipes. The pilot is expected to conclude in 2022. *Id*.

For Greater Pennsylvania, Aqua proffered that it performs a water loss analysis using a form of the AWWA water audit methodology and employs a full-time leak locator who focuses primarily in the Northeastern areas. The Company also asserted that leak detection is outsourced to several contracted professionals throughout Greater Pennsylvania, as needed. Regarding other leak detection efforts, Aqua explained that its distribution field employees are equipped with acoustic leak detection equipment which is utilized each time the employee operates a fire hydrant, flushing device, distribution system valve or customer service valve. *Id*.

Referencing its direct testimony, Aqua noted its capital expenditures program for the years 2018 through 2021 has been weighted toward water main replacement. Yanora-10 (citing Aqua St. 1 at 4). The Company explained that it has approximately 5,800 miles of water main in Pennsylvania, and has been replacing, on average, over 100 miles per year for the last ten years accounting for an average investment of approximately $100 million to $150 million annually. As a result of this investment, the Company contended that it has experienced a reduction in the number of main breaks in cold weather months and an overall tightening up of the system such that recent unaccounted for water levels have been trending downward. In addition, Aqua emphasized that it has acquired many small or troubled systems and made significant improvements in their unaccounted-for-water through main replacement. Specifically, Aqua asserted that it greatly improved the Phoenixville water systems. The Company added that it has also invested in GIS software, which is used to track and monitor main break history and water aesthetic issues due to aging infrastructure. Yanora-10.

In the Recommended Decision, the ALJ referenced the Directed Questions and the Company's responses to them. R.D. at 137. The ALJ also made one specific Finding of Fact pertaining to the Company's responses to the Directed Questions as follows:

> 111. As a matter of the normal course of operations, Aqua operates between 6,000 to 8,000 valves per year, or about 10% of its valves. [Aqua Exh. TMD-4-R]

R.D. at 29. No Party filed Exceptions regarding the Company's Responses to the Directed Questions or to the recommended Finding of Fact.

However, the Parties have developed an evidentiary record pertaining to various quality of service issues that overlap with some of the Directed Question issues, including Unaccounted-for-Water, Pressure Measurements, Isolation Valves, and Fire Hydrants. We have addressed these litigated issues in this Opinion and Order, *supra*. Moreover, we note that the Company's tariff proposal to help remediate customer-owned lead service lines was recently considered and approved in the Commission's *Aqua LSL Order* entered on July 15, 2021.

To the extent that the Directed Questions pertain to additional issues not addressed in the prior litigated issues, we find that Aqua has provided sufficient responses and information which have assisted the Parties and the Commission in evaluating tangential matters which may impact the rate proposals at issue in this proceeding. Upon review, we determine that the Company's responses to the Directed Questions do not alter our ultimate determination herein that the proposed increases in rates, as modified by this Opinion and Order, are just and reasonable.

XIII. Conclusion

Based on our review of the record in this proceeding, we shall: (1) grant, in part, and deny, in part, the Exceptions filed by Aqua, I&E, and the OCA; (2) deny the Exceptions filed by the OSBA, CAUSE-PA, Aqua LUG, Masthope, and Mr. Osinski; and (3) approve an annual revenue increase of $50,510,192 to the Company's *pro forma* revenue at present rates of $510,006,687, or approximately 9.88%, for its water service and an annual revenue increase of $18,740,978 to the Company's *pro forma* revenue at present rates of $37,076,494, or approximately 50.55%, for its wastewater service. **THEREFORE;**

IT IS ORDERED:

1. That the Exceptions filed by Aqua Pennsylvania, Inc., and Aqua Pennsylvania Wastewater, Inc., on February 28, 2022, are granted, in part, and denied, in part, consistent with this Opinion and Order.

2. That the Exceptions filed by the Commission's Bureau of Investigation and Enforcement on February 28, 2022, are granted, in part, and denied, in part, consistent with this Opinion and Order.

3. That the Exceptions filed by the Office of Consumer Advocate on February 28, 2022, are granted, in part, and denied, in part, consistent with this Opinion and Order.

4. That the Exceptions filed by the Office of Small Business Advocate on February 28, 2022, are denied, consistent with this Opinion and Order.

5. That the Exceptions filed by the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania on February 28, 2022, are denied, consistent with this Opinion and Order.

6. That the Exceptions filed by Masthope Mountain Community Association on February 28, 2022, are denied, consistent with this Opinion and Order.

7. That the Exceptions filed by the Aqua Large Users Group on February 28, 2022, are denied, consistent with this Opinion and Order.

8. That the Exceptions filed by Donald C. Osinski on February 21, 2022, are denied, consistent with this Opinion and Order.

9. That the Recommended Decision of Administrative Law Judge Mary D. Long, issued on February 18, 2022, is adopted, as modified, by this Opinion and Order.

10. That Aqua Pennsylvania, Inc., is authorized to grant discounted rates to Chemung County Industrial Development Agency, Horsham Water Authority, and the Borough of Sharpsville consistent with the water resale contracts charging discounted rates pursuant to Aqua Pennsylvania, Inc.'s tariff Rider DRS – Demand Based Resale

Service. The total upward adjustment to Aqua Pennsylvania, Inc.'s revenues as a result of water contract revenue as set forth in Table II – Water shall be $1,136,086.

11. That the corrections and modifications directed by this Opinion and Order reflected in Aqua Pennsylvania, Inc., and Aqua Pennsylvania Wastewater, Inc., Docket Nos. R-2021-3027385 and R-2021-3027386 (Commission Tables Calculating Allowed Revenue Increase), attached hereto, are adopted as being in the public interest.

12. That Aqua Pennsylvania, Inc., shall not place into effect the rates, rules, and regulations contained in proposed Tariff Water - Pa. P.U.C. No. 3, as filed.

13. That Aqua Pennsylvania Wastewater, Inc., shall not place into effect the rates, rules, and regulations contained in proposed Aqua Original Tariff Sewer - Pa. P.U.C. No. 3, as filed.

14. That Aqua Pennsylvania, Inc., is authorized to file tariffs, tariff supplements and/or tariff revisions, on at least one day's notice, and pursuant to the provisions of 52 Pa. Code §§ 53.1, *et seq.*, and 53.101, designed to produce an annual operating revenue of approximately $561,658,784, representing an annual revenue increase of approximately $50,510,192, to become effective for service rendered on and after May 19, 2022.

15. That Aqua Pennsylvania Wastewater, Inc., is authorized to file tariffs, tariff supplements and/or tariff revisions, on at least one day's notice, and pursuant to the provisions of 52 Pa. Code §§ 53.1, *et seq.*, and 53.101, designed to produce an annual operating revenue of approximately $55,817,471, representing an annual revenue increase of approximately $18,740,978, to become effective for service rendered on and after May 19, 2022.

16. That Aqua Pennsylvania, Inc., and Aqua Pennsylvania Wastewater, Inc., shall file detailed calculations with its tariff filings, which shall demonstrate to the Commission's satisfaction that the filed tariff adjustments comply with the provisions of this final Opinion and Order.

17. That Aqua Pennsylvania, Inc., and Aqua Pennsylvania Wastewater, Inc., shall allocate the authorized increase in operating revenue to each service, rate schedule, and customer class, and rate schedule within each rate customer class, in the manner prescribed in this Opinion and Order.

18. That Aqua Pennsylvania, Inc., and Aqua Pennsylvania Wastewater, Inc., shall file with the Commission's Secretary's Bureau at these dockets and provide the Commission's Bureaus of Technical Utility Services and Investigation and Enforcement with updates to schedule G-2 of Aqua Exhibits 1-A, 1-B, 1- C, 1-D, 1-E, 1-F, and 1-G, no later than July 1, 2022, which should include actual capital expenditures, plant additions, and retirements for the 12 months ending March 31, 2022, and, an additional update for actuals for the 12 months ending March 31, 2023, no later than July 1, 2023.

19. That Aqua Pennsylvania, Inc., and Aqua Pennsylvania Wastewater, Inc., shall comply with all directives and conclusions contained in this Opinion and Order that are not the subject of individual ordering paragraphs as if they were the subject of specific ordering paragraphs.

20. That Aqua Pennsylvania, Inc., and Aqua Pennsylvania Wastewater, Inc., shall begin monitoring and reviewing the appropriate customer billing data for purposes of determining, in its next base rate proceeding, if, and to what extent, any offset to its low-income program cost recovery is necessary to avoid any double recovery Aqua Pennsylvania, Inc., and Aqua Pennsylvania Wastewater, Inc., may receive through actual collections after the implementation of its customer assistance programs. Aqua

Pennsylvania, Inc., and Aqua Pennsylvania Wastewater, Inc., shall consult with the Office of Consumer Advocate and the Commission's Bureau of Investigation and Enforcement to determine the necessary data that is needed to accomplish this directive.

21. That Aqua Pennsylvania, Inc., shall develop an isolation valve inspection and exercise program, to be implemented no later than one-hundred and eighty (180) days from the effective date of rates resulting from this base rate proceeding, which establishes a defined schedule for Aqua Pennsylvania, Inc., to inspect and exercise each of its non-critical valves within a set inspection cycle and to maintain records of its attempts to exercise its isolation valves and note whether the operation was successful.

22. That Aqua Pennsylvania, Inc., shall appropriately mark any public fire hydrants in Aqua Pennsylvania, Inc.'s system that cannot provide the minimum fire flow of 500 gallons per minute at 20 pounds per square inch within thirty (30) days of entry of this Opinion and Order.

23. That Aqua Pennsylvania, Inc., and Aqua Pennsylvania Wastewater, Inc., shall require income documentation from an interested customer to certify income eligibility for participation in its customer assistance program and upon recertification in a manner similar to that of the Peoples Companies. Within sixty (60) days of the entry date of this Opinion and Order, Aqua Pennsylvania, Inc., and Aqua Pennsylvania Wastewater, Inc., shall file a written plan with the Commission's Secretary's Bureau at the Dockets in this proceeding, with a copy to be served on the Bureau of Consumer Services, describing the process it will use for certification and recertification of income eligibility for participation in its customer assistance program.

24. That Aqua Pennsylvania, Inc., and Aqua Pennsylvania Wastewater, Inc., shall implement its application process proposed in this proceeding to transition Helping Hand customers who qualify for the new customer assistance program, subject to

the modification that Aqua Pennsylvania, Inc., and Aqua Pennsylvania Wastewater, Inc., shall require income documentation for certification purposes rather than permitting potential program participants to confirm their income through self-attestation.

25. That within six (6) months of the entry date of this Opinion and Order, Aqua Pennsylvania, Inc., and Aqua Pennsylvania Wastewater, Inc., shall file its Community Education and Outreach Plan with the Commission's Secretary's Bureau at these Dockets with copies to be served on the Commission's Bureaus of Consumer Services and Office of Communications. Aqua Pennsylvania, Inc., and Aqua Pennsylvania Wastewater, Inc., shall also file an annual update of its Community Education and Outreach Plan, after the filing of its first Community Education and Outreach Plan at these Dockets until either the filing of its next base rate proceeding or another proceeding addressing its universal service programs.

26. That Aqua Pennsylvania, Inc., and Aqua Pennsylvania Wastewater, Inc., shall consult with the Office of Consumer Advocate and the Commission's Bureau of Investigation and Enforcement regarding the root cause analysis of customer complaint data and cooperatively discuss how this data will be developed to reflect meaningful trends in customer complaint data and potentially reduce contested issues in future proceedings.

27. That the request of Aqua Pennsylvania, Inc., and Aqua Pennsylvania Wastewater, Inc., to continue to record COVID-19 uncollectible expenses in their COVID-19 deferral accounts and to seek recovery in the next rate case proceeding filed by Aqua Pennsylvania, Inc., and Aqua Pennsylvania Wastewater, Inc., is granted. Any deferred amounts that Aqua Pennsylvania, Inc., and Aqua Pennsylvania Wastewater, Inc., seek to recover in their next rate case proceeding shall be subject to detailed review and investigation and the burden of proof will remain with Aqua Pennsylvania, Inc., and

Aqua Pennsylvania Wastewater, Inc., to establish the prudence and reasonableness of their incremental COVID-19 related financial impacts.

28. That the Formal Complaints filed by the Office of the Consumer Advocate at Docket Nos. C-2021-3028466 and C-2021-3028467 are sustained, in part, and dismissed, in part, and shall be marked closed.

29. That the Formal Complaints filed by the Office of Small Business Advocate at Docket Nos. C-2021-3028509 and C-2021-3028511 are dismissed and shall be marked closed.

30. That the Formal Complaints of the Masthope Mount Community Association at Docket Nos. C-2021-3028992 and C-2021-3028996 are dismissed and shall be marked closed.

31. That the Formal Complaint of the Aqua Large Users Group, at Docket No. C-2021-3029089 is dismissed and shall be marked closed.

32. That the following Formal Complaints against Aqua Pennsylvania, Inc., are dismissed and shall be marked closed:

Martha Bronson at Docket No. C-2021-3028132
Neil Kugelman at Docket No. C-2021-3028139
Geoffrey Rhine at Docket No. C-2021-3028170
Theodore Voltolina at Docket No. C-2021-3028194
Aaron Brown at Docket No. C-2021-3028279
Darren Distasio at Docket No. C-2021-3028285
Deena Denesowicz at Docket No. C-2021-3028288
Vivian George at Docket No. C-2021-3028310

Nick Panaccio at Docket No. C-2021-3028331
Richard Regnier at Docket No. C-2021-3028332
Gerald DiNunzio Jr. at Docket No. C-2021-3028362
Nancy Reedman at Docket No. C-2021-3028405
Michael McCall at Docket No. C-2021-3028413
Raymond Cavalieri at Docket No. C-2021-3028448
Byron Goldstein at Docket No. C-2021-3028463
John Grassie at Docket No. C-2021-3028663
Kyle Brophy at Docket No. C-2021-3028712
Daniel Savino at Docket No. C-2021-3028758
Michael Roberts at Docket No. C-2021-3028869
Treasure Lake Property Owners Association Inc. at
Docket No. C-2021-3029004
Gerardo Giannattasio at Docket No. C-2021-3029066
Erik McElwain at Docket No. C-2021-3029135
Judy Burton at Docket No. C-2021-3029152
Brian Edwards at Docket No. C-2021-3029159
Richard Gage at Docket No. C-2021-3029393
Joanne Smyth at Docket No. C-2021-3029411 and
Jane O'Donovan at Docket No. C-2021-3029532.

33. That the following Formal Complaints against Aqua Pennsylvania Wastewater, Inc., are dismissed and shall be marked closed:

Camp Stead Property Owners Association at
Docket No. C-2021-3028928
Dale Markowitz at Docket No. C-2021-3028280
Keith Anthony at Docket No. C-2021-3028444
Stephanie Boris at Docket No. C-2021-3028443

Jennifer Buckley at Docket No. C-2021-3028160
Carl Martinson at Docket No. C-2021-3028312
Elizabeth O'Neill at Docket No. C-2021-3028333
Erik and Ilisha Smith at Docket No. C-2021-3028334
Curtis and Michele Tabor at Docket No. C-2021-3028335
Gregory Valerio at Docket No. C-2021-3028336
Jerome Perch at Docket No. C-2021-3028356
Michael Brull at Docket No. C-2021-3028361
James Blessing at Docket No. C-2021-3028402
Elizabeth Yost at Docket No. C-2021-3028407
Timothy Nicholl at Docket No. C-2021-3028471
Alyssa Reinhart at Docket No. C-2021-3028493
James Kolb at Docket No. C-2021-3028497
Ronald Schneck at Docket No. C-2021-3028547
Matthew Cicalese at Docket No. C-2021-3028566
Ronald and Lora Roebuck at Docket No. C-2021-3028568
Kelly Frich at Docket No. C-2021-3028665
Adam Anders at Docket No. C-2021-3028670
Charleen Falsone at Docket No. C-2021-3028760
Stephen Grugeon at Docket No. C-2021-3028892
Lynne Germscheid at Docket No. C-2021-3028860
Deborah and James Popson at Docket No. C-2021-3028868
Masthope Mountain Community Association at
Docket No. C-2021-3028996
Treasure Lake Property Owners Association Inc.at
Docket No. C-2021-3029006
East Norriton Township at Docket No. C-2021-3029019
Kevin Amerman at Docket No. C-2021-3029063
James Wharton Jr. at Docket No. C-2021-3029065

Peter and Kim Ginopolas at Docket No. C-2021-3029096

Yefim Shnayder at Docket No. C-2021-3029134

Andrea and Matthew Rivera at Docket No. C-2021-3029154

Judy Burton at Docket No. C-2021-3029139

Brian Edwards at Docket No. C-2021-3029161

Edward Coccia at Docket No. C-2021-3028870

John Day at Docket No. C-2021-3028734

Robert Dolan at Docket No. C-2021-3028798

Anthony Giovannone at Docket Nos. C-2021-3028794,
C-2021-3028803, C-2021-3028802

Sheila Gutzait at Docket No. C-2021-3028634

Rudolph Hofbauer at Docket No. C-2021-3028666

Ronald and Alexis Koenig at Docket No. C-2021-3028483

Joan Lipski at Docket No. C-2021-3028475

William and Ana Loftus at Docket No. C-2021-3028617

Stephen and Teresa Mason at Docket No. C-2021-3028576

David Monroe at Docket No. C-2021-3028567

Lisa Rampone at Docket No. C-2021-3028804

Lorraine Rocci at Docket No. C-2021-3028499

David Ross at Docket No. C-2021-3028479

Carolyn Sica at Docket No. C-2021-3028446

Dean Swink at Docket No. C-2021-3028604

Francine Weiner at Docket No. C-2021-3028639

Tom Woodward at Docket No. C-2021-3028927

Joseph Torello at Docket No. C-2021-3029180

Donald Osinski at Docket No. C-2021-3029413

Lake Associates LLC at Docket Nos. C-2021-3029425
C-2021-3029422, C-2021-3029419

29 Estates LLC at Docket No. C-2021-3029417

David Bowers at Docket No. C-2021-3029466 and
Joanne Smyth at Docket No. C-2021-3029411.

34. That a copy of this Opinion and Order be served on the Bureau of Consumer Services, Division of Policy; the Bureau of Investigation and Enforcement; and the Bureau of Technical Utility Services, Finance/Tariff Division for monitoring and compliance.

BY THE COMMISSION,

Rosemary Chiavetta
Secretary

(SEAL)

ORDER ADOPTED: May 12, 2022

ORDER ENTERED: May 16, 2022

LIST OF ABBREVIATIONS

ADIT	Accumulated Deferred Income Tax
ALJ	Administrative Law Judge
ANSI	American National Standards Institute
Aqua	Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc.
Aqua LUG	Aqua Large Users Group
ASSE	American Society of Sanitary Engineers
AWWA	American Water Works Association
BCS	Bureau of Consumer Services
CAC	customer advances for construction
CAP	Customer Assistance Program
CAPM	capital asset pricing model
CAUSE-PA	Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania
CE	comparable earnings
CEOP	Community Education and Outreach Plan
CIAC	contributions in aid of construction
CIS	customer information system
COSS	cost of service study
CPI	Consumer Price Index
CRR	Competitive Rate Rider
CSIC	Collection System Improvement Charge
CWC	Cash Working Capital
DCF	discounted cash flow
DCNR	Department of Conservation and Natural Resources
DRS	Demand Based Resale Service
DSIC	Distribution System Improvement Charge
ECA	Energy Cost Adjustment
ECAM	Energy Cost Adjustment Mechanism
EDC	Electric Distribution Company
EDU	Equivalent Dwelling Unit
FERC	Federal Energy Regulatory Commission
FMV	Fair Market Value
FPFTY	fully projected future test year
FPL	Federal Poverty Level
FTAS	Federal Tax Adjustment Surcharge
FTY	future test year
FY	Fiscal Year
GDP	gross domestic product

GIS	Geographic Information System
gpm	gallons per minute
HTY	historical test year
I&E	Bureau of Investigation and Enforcement
I&I	inflow and infiltration
IRS	Internal Revenue Service
IVR	Interactive Voice Response
LEP	Limited English proficient/proficiency
M&S	Materials and Supplies
Masthope	Masthope Mountain Community Association
NFG	National Fuel Gas Distribution Corporation
NGDC	Natural Gas Distribution Company
NOPR	Notice of Proposed Rulemaking
O&M	Operating and Maintenance
OCA	Office of Consumer Advocate
OSBA	Office of Small Business Advocate
PADEP	Pennsylvania Department of Environmental Protection
PAWC	Pennsylvania-American Water Company
PFAS	per and poly-fluoro alklyl substances
PGC	Purchased Gas Cost
PIP	Percentage of Income Payment Plan
psi	per square inch
PWA	Purchased Water Adjustment
PWAC	Purchased Water Adjustment Clause
PWSA	Pittsburgh Water and Sewer Authority
RCA	Root Cause Analysis
Rf	risk-free rate of return
ROE	return on equity
RP	risk premium
RROR	Relative Rate of Return
SEPA	Southeast Pennsylvania
SERP	Supplemental Executive Retirement Plan
STAS	State Tax Adjustment Surcharge
TCJA	Tax Cuts and Jobs Act of 2017
TUS	Bureau of Technical Utility Services
UFW	Unaccounted For Water
UPAA	utility plant acquisition adjustments
US OMB	United States Office of Management and Budget
USECP	Universal Service Energy and Conservation Plan

USP	Universal Service Program
USPS	United States Postal Service
USR	Universal Service Rider
WWTP	Wastewater Treatment Plant

Pennsylvania Public Utility Commission

v.

Aqua Pennsylvania, Inc.
Aqua Pennsylvania Wastewater, Inc
Docket Nos. R-2021-3027385
R-2021-2027386

Commission Tables Calculating Allowed Revenue Increase

<u>Table Act 11</u>	**Act 11 Water and Wastewater Revenue Requirement Summary**
<u>Table RevSum</u>	**Water and Wastewater Revenue Summary**

<u>Water Tables</u>

Table I	**Income Summary**
Table IA	**Rate of Return**
Table IB	**Revenue Factor**
Table II	**Adjustments**
Table III	**Interest Synchronization**
Table IV	**Cash Working Capital: Interest and Dividends**
Table V	**Cash Working Capital: Taxes**
Table VI	**Cash Working Capital: O&M Expense**

Wastewater-Base Tables

Table I	**Income Summary**
Table IA	**Rate of Return**
Table IB	**Revenue Factor**
Table II	**Adjustments**
Table III	**Interest Synchronization**
Table IV	**Cash Working Capital: Interest and Dividends**
Table V	**Cash Working Capital: Taxes**
Table VI	**Cash Working Capital: O&M Expense**

Wastewater-Limerick Tables

Table I	**Income Summary**
Table IA	**Rate of Return**
Table IB	**Revenue Factor**
Table II	**Adjustments**
Table III	**Interest Synchronization**
Table IV	**Cash Working Capital: Interest and Dividends**
Table V	**Cash Working Capital: Taxes**
Table VI	**Cash Working Capital: O&M Expense**

Wastewater-East Bradford Tables

Table I	**Income Summary**
Table IA	**Rate of Return**
Table IB	**Revenue Factor**
Table II	**Adjustments**
Table III	**Interest Synchronization**
Table IV	**Cash Working Capital: Interest and Dividends**
Table V	**Cash Working Capital: Taxes**
Table VI	**Cash Working Capital: O&M Expense**

Wastewater-Cheltenham Tables

Table I	**Income Summary**
Table IA	**Rate of Return**
Table IB	**Revenue Factor**
Table II	**Adjustments**
Table III	**Interest Synchronization**
Table IV	**Cash Working Capital: Interest and Dividends**
Table V	**Cash Working Capital: Taxes**
Table VI	**Cash Working Capital: O&M Expense**

Wastewater-East Norriton Tables

Table I	**Income Summary**
Table IA	**Rate of Return**
Table IB	**Revenue Factor**
Table II	**Adjustments**
Table III	**Interest Synchronization**
Table IV	**Cash Working Capital: Interest and Dividends**
Table V	**Cash Working Capital: Taxes**
Table VI	**Cash Working Capital: O&M Expense**

Wastewater-New Garden Tables

Table I	**Income Summary**
Table IA	**Rate of Return**
Table IB	**Revenue Factor**
Table II	**Adjustments**
Table III	**Interest Synchronization**
Table IV	**Cash Working Capital: Interest and Dividends**
Table V	**Cash Working Capital: Taxes**
Table VI	**Cash Working Capital: O&M Expense**

Docket Nos. R-2021-3027385, R-2021-3027386

Commission Final Allowance
AQUA PENNSYLVANIA, INC.

TABLE ACT 11 - WATER AND WASTEWATER REVENUE REQUIREMENT - SUMMARY

Line No.	Description	Total Company (a)	Water Operations (b)	Wastewater Base Operations (c)	Wastewater Limerick (d)	Wastewater East Bradford (e)	Wastewater Cheltenham (f)	Wastewater East Norriton (g)	Wastewater New Garden (h)
1	Present Rate Revenue	$ 548,225,086	$ 511,148,592	$ 19,011,761	$ 3,978,573	$ 1,014,569	$ 7,258,740	$ 2,923,770	$ 2,889,080
2	Additional Revenue Requirement	69,328,876	39,323,400	15,616,886	5,581,376	777,094	2,752,399	2,739,266	2,538,455
3	Act 11 Allocation, Gross, Unadjusted [1]	(0)	11,264,498	(8,779,582)	(2,310,744)	(128,024)	2,033,271	(1,080,283)	(999,136)
4	Revenue Factor [2]	-	70.27%	69.78%	69.78%	69.78%	69.78%	69.78%	69.78%
5	Net Income Available for Return [3]	54,601	7,915,126	(6,126,516)	(1,612,470)	(89,337)	1,418,845	(753,837)	(697,211)
6	Act 11 Allocation Adjustment, Gross [4]	(77,706)	(77,706)	-	-	-	-	-	-
7	Act 11 Allocation, Gross, Adjusted [5]	(77,706)	11,186,792	(8,779,582)	(2,310,744)	(128,024)	2,033,271	(1,080,283)	(999,136)
8	Proposed Revenues [6]	$ 617,476,255	$ 561,658,784	$ 25,849,065	$ 7,249,205	$ 1,663,639	$ 12,044,410	$ 4,582,752	$ 4,428,399
9	Rate Increase/(Decrease) - $	$ 69,251,169	$ 50,510,192	$ 6,837,304	$ 3,270,632	$ 649,070	$ 4,785,671	$ 1,658,983	$ 1,539,319
10	Rate Increase/(Decrease) - %	12.63%	9.88%	35.96%	82.21%	63.97%	65.93%	56.74%	53.28%
11	Total Rate Increase/(Decrease) - $ For Wastewater Operations			$ 18,740,978					
12	Total Rate Increase/(Decrease) - % For Wastewater Operations			50.55%					

Notes to accompany Table Act 11 – Water and Wastewater Revenue Requirement – Summary

(1) The allocation between wastewater and water operations is achieved by the proposed consolidation of water and wastewater revenue requirements to derive the water and wastewater rates in this case.

(2) See the revenue factors in Table IB for each rate group to determine the gross, unadjusted Act 11 Allocation.

(3) Line No. 3 x Line No. 4.

(4) Reduce the gross water revenue requirement resulting from the Act 11 Allocation by dividing Line No. 5, Column (a) by Line No. 4, Column (b) and assigning this adjustment to water. This provides the Company the same net income from water customers as if the revenue requirement were charged to wastewater customers, since water customers have a lower uncollectible account rate.

(5) Line No. 3 + Line No. 6.

(6) Line No. 1 + Line No. 2 + Line No. 7.

Docket Nos. R-2021-3027385, R-2021-3027386

Commission Final Allowance
AQUA PENNSYLVANIA, INC.

TABLE REVSUM - WATER AND WASTEWATER REVENUE SUMMARY

Line No.	Description		Total Company		Water Operations		Wastewater Base Operations		Wastewater Limerick		Wastewater East Bradford		Wastewater Cheltenham		Wastewater East Norriton		Wastewater New Garden
			(a)		(b)		(c)		(d)		(e)		(f)		(g)		(h)
1	Current General Service Revenues [1][3]	$	546,693,727	$	509,695,526	$	18,988,325	$	3,969,765	$	1,013,716	$	7,238,362	$	2,916,335	$	2,871,698
2	Proposed General Service Revenues	$	615,829,068	$	560,132,914	$	25,817,242	$	7,233,172	$	1,662,240	$	12,010,599	$	4,571,144	$	4,401,756
3	Rate Increase/(Decrease) - $	$	69,135,342	$	50,437,388	$	6,828,917	$	3,263,407	$	648,524	$	4,772,237	$	1,654,809	$	1,530,058
4	Rate Increase/(Decrease) - %		12.65%		9.90%		35.96%		82.21%		63.97%		65.93%		56.74%		53.28%
5	Current Forfeited Discount Revenues [2]	$	813,782	$	735,710	$	23,317	$	8,788	$	853	$	20,377	$	7,355	$	17,382
6	Proposed Forfeited Discount Revenues	$	929,610	$	808,513	$	31,703	$	16,012	$	1,399	$	33,812	$	11,528	$	26,643
7	Rate Increase/(Decrease) - $	$	115,828	$	72,803	$	8,386	$	7,224	$	546	$	13,435	$	4,173	$	9,261
8	Rate Increase/(Decrease) - %		12.65%		9.90%		35.96%		82.21%		63.97%		65.93%		56.74%		53.28%
9	Current Miscellaneous Revenues [3][4]	$	717,577	$	717,357	$	120	$	20	$	-	$	-	$	80	$	-
10	Proposed Miscellaneous Revenues	$	717,577	$	717,357	$	120	$	20	$	-	$	-	$	80	$	-
11	Rate Increase/(Decrease) - $	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-
12	Rate Increase/(Decrease) - %		0.00%		0.00%		0.00%		0.00%						0.00%		
13	Total Operating Revenues [5]	$	617,476,255	$	561,658,784	$	25,849,065	$	7,249,205	$	1,663,639	$	12,044,410	$	4,582,752	$	4,428,399
14	Proposed Revenues [6]	$	617,476,255	$	561,658,784	$	25,849,065	$	7,249,205	$	1,663,639	$	12,044,410	$	4,582,752	$	4,428,399
15	Difference, Lines 14 and 13		-		-		-		-		-		-		-		-

Notes and Sources to Accompany Table RevSum

The Company will need to increase General Service and Forfeited Discount revenues by the same percentage to achieve the total indicated operating revenues, as evidenced by a proof of revenue.

(1) See Aqua Exhibits 1-A to 1-F(f) at Schedule B-1, Line "Total Sales to General Customers". Water general service revenues are adjusted for imputed revenues. *See* Table II - Water, Notes 2 and 6.

(2) See Aqua Exhibits 1-A to 1-F(f) at Schedule B-1, Line "Forfeited Discounts". For water, Aqua indicated that $735,710 was attributable to forfeited discount revenue in the historic test year. *See* Aqua St. 2-R at 29.

(3) For Wastewater - East Bradford, General Service revenues are increased by $15,525 and Miscellaneous revenues are decreased by the same amount. This amount represents charges for General Service described as "Contract Sales for Resale - Unmetered - Single Family - Birmingham Twp.". *See* Aqua's rate filing at Schedule EB-4, Page 1 and Exhibit 1-D(d), Schedule B-1, Line No. 9.

(4) See Aqua Exhibits 1-A to 1-F(f) at Schedule B-1, Lines "Other WW Revenues" and "Miscellaneous WW Service Revenues". Unlike Forfeited Discount revenues, Miscellaneous revenues aren't expected to increase proportionately with General Service revenues. For water, miscellaneous revenues are reduced by forfeited discount revenues. *See* Note 2.

(5) Sum of Line Nos. 2, 6, and 10.

(6) *See* Table Act 11, Line No. 8.

Commission Final Allowance
TABLE I - Water
Aqua Pennsylvania, Inc.
INCOME SUMMARY
R-2021-3027385, R-2021-3027386

	Pro Forma Present Rates[1]	Company Adjustments [1][2]	Pro Forma Present Rates (Revised) [1][2]	Commission Adjustments	Commission Pro Forma Present Rates	Commission Revenue Increase [3]	Total Allowable Revenues
	$	$	$	$	$	$	$
Operating Revenue	$ 510,006,687	$ -	$ 510,006,687	$ 1,141,906	$ 511,148,592	$ 39,323,400	$ 550,471,992
Expenses:							
O & M Expense	116,459,234	-	116,459,234	(1,895,043)	114,564,192	201,431	114,765,623
Depreciation	122,166,578	-	122,166,578	(121,865)	122,044,713	-	122,044,713
Taxes, Other	12,450,066	-	12,450,066	7,669	12,457,734	264,080	12,721,814
Income Taxes:							
State	5,345,514	11,184	5,356,698	318,777	5,675,475	3,881,903	9,557,378
Federal	7,677,005	21,161	7,698,166	603,160	8,301,326	7,344,957	15,646,283
Total Expenses	264,098,397	32,345	264,130,742	(1,087,302)	263,043,440	11,692,371	274,735,811
Net Inc. Available for Return	245,908,290	$ (32,345)	$ 245,875,945	$ 2,229,207	$ 248,105,152	$ 27,631,028	$ 275,736,181
Rate Base	3,818,456,012	(6,077,218)	3,812,378,794	(2,161,832)	3,810,216,962		3,810,216,962
Rate of Return	6.44%		6.45%		6.51%		7.23675800%

[1] Company Main Brief
[2] Company Main Brief Section III.E.2 & AP Stmt. 8-R
[3] Revenue increases before Section 1311(c) allocation from water to wastewater

Pre-Act 11 Allocation Revenue Change (%): 7.69%

Commission Final Allowance
TABLE I(A) - Water
Aqua Pennsylvania, Inc.
RATE OF RETURN
R-2021-3027385, R-2021-3027386

	Structure	Cost	After-Tax Weighted Cost	Effective Tax Rate Complement	Pre-Tax Weighted Cost Rate
Total Cost of Debt			1.84216100%		1.84%
Long-term Debt	46.05%	4.00%	1.84216100%		1.84%
Short-term Debt	0.00%	0.00%	0.00000000%		0.00%
Preferred Stock	0.00%	0.00%	0.00000000%	0.711079	0.00%
Common Equity	53.95%	10.00%	5.39459700%	0.711079	7.59%
	100.00%		7.23675800%		9.43%
Pre-Tax Interest Coverage	5.12				
After-Tax Interest Coverage	3.93				
Tax Rate Complement (1-(21%+(9.99% X (1-21%))	71.10790%				

Commission Final Allowance
Aqua Pennsylvania, Inc.
TABLE I(B) - Water
REVENUE FACTOR
R-2021-3027385, R-2021-3027386

100%	1.00000000
Less:	
Uncollectible Accounts Factor (*)	0.00512242
PUC, OCA, OSBA, DPC Assessment Factors (*)	0.00671560
Gross Receipts Tax	0.00000000
Other Tax Factors	0.00000000
	0.98816198
State Income Tax Rate (*)	0.09990000
Effective State Income Tax Rate	0.09871738
Factor After Local and State Taxes	0.88944460
Federal Income Tax Rate (*)	0.21000000
Effective Federal Income Tax Rate	0.18678337
Revenue Factor (100% - Effective Tax Rates)	0.70266123

(*) Company Main Brief

Commission Final Adjustments
TABLE II - Water
SUMMARY OF ADJUSTMENTS
R-2021-3027385, R-2021-3027386

Adjustments	Rate Base	Revenues	Expenses	Depreciation	Taxes-Other	State Income Tax	Federal Income Tax
	$	$	$	$	$	$	$
RATE BASE:							
CWC:							
Int. & Div. (Table IV)	4,950						
Taxes (Table V)	431,945						
O & M (Table VI)	(161,422)						
Acquis. Adj. - Phoenixville [1]	(2,437,305)						
REVENUES:							
Water Contract Revenue [2][7][8]		1,136,086	5,820		7,630	112,151	212,202
Negotiated Water Contracts [6]		0	0		0	0	0
Concomitant Forfeited Discounts [7][8]		5,820	30		39	574	1,087
EXPENSES:							
						0	0
Supp. Exec. Retire. Program [3]			(635,612)			69,492	131,485
General Inflation [4]			(864,335)			86,347	163,377
Gen. Liab. Insurance [5]			(340,945)			34,060	64,446
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
						0	0
Amort. Phoenixville Acquis. Adj. [1][8]				(121,865)		12,174	23,035
						0	0
TAXES:						0	0
				0		3,979	7,528
Interest Synchronization (Table III)							
TOTALS	(2,161,832)	1,141,906	(1,835,043)	(121,865)	7,669	318,777	603,160

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Notes to Accompany Table II - Water

(1) Remove Phoenixville acquisition adjustment and associated amortization expense.

(2) Add imputed general service revenue for Rider DRS contracts for New Wilmington [$348,904] and Masury [$787,182]. [$348,904 + $787,182 = $1,136,086]. *See* I&E Exh. 4-SR, Sch. 1. However, as we are granting Aqua's Exception No. 3, in part, imputed general service revenue for Rider DRS contracts associated with Chemung, Horsham, and Sharpsville are not added back.

(3) Remove Supplemental Executive Retirement Program expenses.

(4) Remove general inflation adjustment.

(5) Adopt I&E's position regarding general liability insurance expense.

(6) Grant Aqua's Exception No. 4, which removes the ALJ's recommended upward adjustment

(7) Revenues increased by the sum of one plus the uncollectible accounts factor in Table IB Water to include additional imputed forfeited discount revenue. Expenses includes additional bad debt expense as the product of additional revenues times the uncollectible accounts factor in Table IB Water. Taxes-Other includes additional assessment expenses as the product of additional revenues times the assessment factor in Table IB Water. Expenses and Taxes-Other are deducted from revenue when determining State and Federal Income Taxes.

(8) Cash working capital is not adjusted for non-cash expenses (*i.e.*, incremental bad debt expense and amortization expense).

Commission Final Allowance
TABLE III - Water
Aqua Pennsylvania, Inc.
INTEREST SYNCHRONIZATION
R-2021-3027385, R-2021-3027386

	Amount $
Company Rate Base Claim [1]	3,812,378,794
Commission Rate Base Adjustments (From Table II)	(2,161,832)
Commission Rate Base (Line 1 - Line 2)	3,810,216,962
Weighted Cost of Debt (From Table IA)	1.84216100%
Commission Interest Expense (Line 3 x Line 4)	70,190,331
Company Claim [1]	70,342,109
Total Commission Adjustment (Line 6 - Line 5)	151,778
Company Adjustment [1][2]	111,952
Net Commission Interest Adjustment (Line 7 - Line 8)	39,826
State Income Tax Rate	9.99%
State Income Tax Adjustment (Line 9 x Line 10) (Flow to Table II)	3,979
Net Commission Interest Adjustment (Line 9)	39,826
State Income Tax Adjustment (Line 11)	3,979
Net Commission Adjustment for F.I.T. (Line 9 - Line 11)	35,847
Federal Income Tax Rate	21.00%
Federal Income Tax Adjustment (Line 12 x Line 13) (Flow to Table II)	7,528

[1] Company Main Brief
[2] Rate Base Company Adjustment times weighted cost of debt

Commission Final Allowance
TABLE IV - Water
Aqua Pennsylvania, Inc.
CASH WORKING CAPITAL - Interest and Dividends
R-2021-3027385, R-2021-3027386

Accrued Interest	Long-Term Debt	Short-Term Debt	Preferred Stock Dividends	
Company Rate Base Claim	$3,812,378,794	$3,812,378,794	Company Rate Base Claim	$3,812,378,794
Commission Rate Base Adjustments	($2,161,832)	($2,161,832)	Commission Rate Base Adjustments	($2,161,832)
Commission Rate Base	$3,810,216,962	$3,810,216,962	Commission Rate Base	$3,810,216,962
Weighted Cost of Debt	1.84216100%	0.00%	Weighted Cost Pref. Stock	0.00000000%
Commission Annual Interest Exp.	$70,190,331	$0	Commission Preferred Dividends	$0
Average Revenue Lag Days	45.1	45.1	Average Revenue Lag Days	45.1
Average Expense Lag Days	90.3	90.3	Average Expense Lag Days	90.3
Net Lag Days	-45.2	-45.2	Net Lag Days	-45.2
Working Capital Adjustment				
Commission Daily Interest Exp.	$192,302	$0	Commission Daily Dividends	$0
Net Lag Days	-45.2	-45.2	Net Lag Days	-45.2
Commission Working Capital	($8,692,050)	$0		$0
Company Claim [1][2]	($8,697,000)	$0	Company Claim [1][2]	$0
Commission Adjustment	$4,950	$0		$0
Total Interest & Dividend Adj.	$4,950			

[1] Company Main Brief.
[2] Company claim rounded to nearest thousandth

Commission Final Allowance
TABLE V - Water
Aqua Pennsylvania, Inc.
CASH WORKING CAPITAL - TAXES
R-2021-3027385, R-2021-3027386

Description	Company Proforma Tax Expense Present Rates	Commission Adjustments	Commission Pro forma Tax Expense Present Rates	Commission Allowance	Commission Adjusted Taxes at Present Rates	Daily Expense	Net Lead/ Lag Days [2]	Accrued Tax Adjustment
Assessments [2]	$3,425,001	$7,669	$3,432,670	$264,080	$3,696,750	$10,128.08	-197.50	($2,000,296)
Public Utility Realty	$4,800,000	$0	$4,800,000		$4,800,000	$13,150.68	-11.30	($148,603)
Capital Stock Tax	$0	$0	$0		$0	$0.00	0.00	$0
Local property taxes & misc.	$1,073,227		$1,073,227		$1,073,227	$2,940.35	-167.00	($491,038)
FICA Taxes - Hourly	$2,470,719		$2,470,719		$2,470,719	$6,769.09	8.50	$57,537
FICA Taxes - Executive & Exempt	$1,729,006		$1,729,006		$1,729,006	$4,737.00	12.00	$56,844
Federal Unemployment Tax	$26,883		$26,883		$26,883	$73.65	75.00	$5,524
PA Unemployment Tax	$276,017		$276,017		$276,017	$756.21	75.00	$56,716
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
State Income Tax	$5,783,096	$318,777	$6,101,873	$3,881,903	$9,983,776	$27,352.81	45.20	$1,236,347
Federal Income Tax	$13,101,742	$603,160	$13,704,902	$7,344,957	$21,049,859	$57,670.85	33.40	$1,926,206
	$32,685,691	$929,606	$33,615,296	$11,490,940	$45,106,236	$123,578.72	5.66	$699,237

[1] Company Main Brief
[2] See Table II - Water, Note 2.

Average Lag Days in Receipt of Revenues	45.1
Average Lag in Payment of Taxes	5.7
Net Lag	39
Average Daily Tax Expense	123,579
Commission Cash Working Capital for Taxes	4,873,945
Less Company Claim [1]	4,442,000
Commission Adjustment	431,945

Commission Final Allowance
TABLE VI - Water
Aqua Pennsylvania, Inc.
CASH WORKING CAPITAL -- O & M EXPENSE
R-2021-3027385, R-2021-3027386

Description	Company Pro forma F.T.Y. Expense	Commission	Commission Pro forma Expenses	Lag Days	Lag Dollars
Hourly Labor	$21,691,942	$0	$21,691,942	7.50	$162,689,568
Non-Union Labor	$14,922,316	$0	$14,922,316	11.00	$164,145,477
Management Fee [3]	$18,159,655	($695,612)	$17,464,043	16.00	$279,424,681
Electric Power	$8,264,721	$0	$8,264,721	20.73	$171,297,822
Water Purchased	$4,148,773	$0	$4,148,773	32.55	$135,036,763
Employee Group Insurance	$5,966,463	$0	$5,966,463	16.00	$95,463,405
Liability Insurance [5]	$7,021,825	($340,945)	$6,680,880	-1.37	($9,151,630)
SFI Postage	$1,344,879	$0	$1,344,879	-7.96	($10,706,644)
Pension	$3,990,000	$0	$3,990,000	300.60	$1,199,377,034
SFAS106	$27,361	$0	$27,361	365.67	$10,005,097
All Other Expenses	$27,451,796	$0	$27,451,796	25.50	$700,020,787
General Inflation [4]	$0	($864,335)	($864,335)	25.90	($22,386,273)
	$0		$0	0.00	$0
	$0		$0	0.00	$0
	$0		$0	0.00	$0
	$0		$0	0.00	$0
	$112,989,731	($1,900,892)	$111,088,839	25.90	$2,875,216,087

Commission Average Revenue Lag	45.1	
Less: Commission Avg. Expense Lag	25.9	
Net Difference	19.2	Days
Commission Pro forma O & M Expense per Day	$304,353	
Commission CWC for O & M	$5,843,578	
Less: Company Claim [1][2]	$6,005,000	
Commission Adjustment	($161,422)	

Notes and Sources to Accompany Table VI – Water

(1) Company Main Brief

(2) Company claim rounded to nearest thousandth

(3) See Table II- Water, Note 3. Most SERP expenses are under the management fee account. OCA Exhibit LA-3 at Page 63.

(4) See Table II - Water, Note 4. We reject increases Aqua made to all expense accounts included in its general inflation claim. Since Exhibits 1-A to 1-G at Schedules C-4.1 and G-5.2 use different item descriptions, the number of lag days used for this adjustment is equal to the weighted average O & M Expense lag days for this rate zone after all other adjustments are applied.

(5) See Table II - Water, Note 5.

Commission Final Allowance

TABLE I - Wastewater - Base

Aqua Pennsylvania Wastewater, Inc. - Base

INCOME SUMMARY

R-2021-3027385, R-2021-3027386

	Pro Forma Present Rates[1]	Company Adjustments [1]	Pro Forma Present Rates (Revised) [1]	Commission Adjustments	Commission Pro Forma Present Rates	Commission Revenue Increase [2]	Total Allowable Revenues
	$	$	$	$	$	$	$
Operating Revenue	$ 19,011,761	$ -	$ 19,011,761	$ -	$ 19,011,761	$ 15,616,886	$ 34,628,647
Expenses:							
O & M Expense	9,830,816	-	9,830,816	(150,101)	9,680,715	186,452	9,867,167
Depreciation	7,780,016	-	7,780,016	-	7,780,016	-	7,780,016
Taxes, Other	303,529	-	303,529	-	303,529	104,877	408,406
Income Taxes:							
State	(1,181,921)	-	(1,181,921)	14,597	(1,167,324)	1,531,023	363,699
Federal	(1,086,251)	-	(1,086,251)	27,620	(1,058,631)	2,896,852	1,838,221
Total Expenses	15,646,188	-	15,646,188	(107,884)	15,538,304	4,719,204	20,257,508
Net Inc. Available for Return	3,365,573	$ -	$ 3,365,573	$ 107,884	$ 3,473,458	$ 10,897,682	$ 14,371,140
Rate Base	198,368,990	-	198,368,990	216,340	198,585,330		198,585,330
Rate of Return	1.70%		1.70%		1.75%		7.23675800%

[1] Company Main Brief

[2] Revenue increases before Section 1311(c) allocation from water to wastewater

Pre-Act 11 Allocation Revenue Change (%): 82.14%

Commission Final Allowance

TABLE I(A) - Wastewater - Base

Aqua Pennsylvania Wastewater, Inc. - Base

RATE OF RETURN

R-2021-3027385, R-2021-3027386

	Structure	Cost	After-Tax Weighted Cost	Effective Tax Rate Complement	Pre-Tax Weighted Cost Rate
Total Cost of Debt			1.84216100%		1.84%
Long-term Debt	46.05%	4.00%	1.84216100%		1.84%
Short-term Debt	0.00%	0.00%	0.00000000%		0.00%
Preferred Stock	0.00%	0.00%	0.00000000%	0.711079	0.00%
Common Equity	53.95%	10.00%	5.39459700%	0.711079	7.59%
	100.00%		7.23675800%		9.43%
Pre-Tax Interest Coverage	5.12				
After-Tax Interest Coverage	3.93				
Tax Rate Complement (1-(21%+(9.99% X (1-21%))	71.10790%				

Commission Final Allowance
Aqua Pennsylvania Wastewater, Inc. - Base
TABLE I(B) - Wastewater - Base
REVENUE FACTOR
R-2021-3027385, R-2021-3027386

100%	1.00000000
Less:	
Uncollectible Accounts Factor (*)	0.01193911
PUC, OCA, OSBA, DPC Assessment Factors (*)	0.00671560
Gross Receipts Tax	0.00000000
Other Tax Factors	0.00000000
	0.98134529
State Income Tax Rate (*)	0.09990000
Effective State Income Tax Rate	0.09803639
Factor After Local and State Taxes	0.88330890
Federal Income Tax Rate (*)	0.21000000
Effective Federal Income Tax Rate	0.18549487
Revenue Factor (100% - Effective Tax Rates)	0.69781403

(*) Company Main Brief

Commission Final Adjustments
TABLE II - Wastewater - Base
SUMMARY OF ADJUSTMENTS
R-2021-3027385, R-2021-3027386

Adjustments	Rate Base	Revenues	Expenses	Depreciation	Taxes-Other	State Income Tax	Federal Income Tax
	$	$	$	$	$	$	$
RATE BASE:							
CWC:							
Int. & Div. (Table IV)	(945)						
Taxes (Table V)	226,646						
O & M (Table VI)	(9,361)						
REVENUES:							
					0	0	0
EXPENSES:							
						0	0
Supp. Exec. Retire. Program [1]			(23,373)			2,335	4,418
General Inflation [2]			(145,368)			14,522	27,478
Gen. Liab. Insurance [3]			18,640			(1,862)	(3,523)
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
TAXES:						0	0
						0	0
Interest Synchronization (Table III)						(398)	(753)
TOTALS	216,340	0	(150,101)	0	0	14,597	27,620

Notes to Accompany Table II – Wastewater - Base

(1) Remove SERP Expenses. The OCA's $57,050 adjustment is allocated to each wastewater rate zone based on the relative percentage of management fees assigned to each rate zone per Aqua Exhibits 1-B to 1-G at Schedule C-1. Since Wastewater - Base is assigned $714,262 of $1,743,416 in total management fees, this adjustment is calculated as follows: [–$57,050 x ($714,262 / $1,743,416)= –$23,373].

(2) Remove general inflation adjustment.

(3) Adopt I&E's position regarding general liability insurance expense.

Commission Final Allowance
TABLE III - Wastewater - Base
Aqua Pennsylvania Wastewater, Inc. - Base
INTEREST SYNCHRONIZATION
R-2021-3027385, R-2021-3027386

	Amount $
Company Rate Base Claim [1]	198,368,990
Commission Rate Base Adjustments (From Table II)	216,340
Commission Rate Base (Line 1 - Line 2)	198,585,330
Weighted Cost of Debt (From Table IA)	1.84216100%
Commission Interest Expense (Line 3 x Line 4)	3,658,261
Company Claim [1]	3,654,276
Total Commisson Adjustment (Line 6 - Line 5)	(3,985)
Company Adjustment [1]	0
Net Commission Interest Adjustment (Line 7 - Line 8)	(3,985)
State Income Tax Rate	9.99%
State Income Tax Adjustment (Line 9 x Line 10) (Flow to Table II)	(398)
Net Commission Interest Adjustment (Line 9)	(3,985)
State Income Tax Adjustment (Line 11)	(398)
Net Commission Adjustment for F.I.T. (Line 9 - Line 11)	(3,587)
Federal Income Tax Rate	21.00%
Federal Income Tax Adjustment (Line 12 x Line 13) (Flow to Table II)	(753)

[1] Company Main Brief

Commission Final Allowance

TABLE IV - Wastewater - Base

Aqua Pennsylvania Wastewater, Inc. - Base

CASH WORKING CAPITAL - Interest and Dividends

R-2021-3027385, R-2021-3027386

Accrued Interest	Long-Term Debt	Short-Term Debt	Preferred Stock Dividends	
Company Rate Base Claim	$198,368,990	$198,368,990	Company Rate Base Claim	$198,368,990
Commission Rate Base Adjustments	$216,340	$216,340	Commission Rate Base Adjustmer	$216,340
Commission Rate Base	$198,585,330	$198,585,330	Commission Rate Base	$198,585,330
Weighted Cost of Debt	1.84216100%	0.00%	Weighted Cost Pref. Stock	0.00000000%
Commission Annual Interest Exp.	$3,658,261	$0	Commission Preferred Dividends	$0
Average Revenue Lag Days	50.2	50.2	Average Revenue Lag Days	50.2
Average Expense Lag Days	91.3	91.3	Average Expense Lag Days	91.3
Net Lag Days	-41.1	-41.1	Net Lag Days	-41.1
Working Capital Adjustment				
Commission Daily Interest Exp.	$10,023	$0	Commission Daily Dividends	$0
Net Lag Days	-41.1	-41.1	Net Lag Days	-41.1
Commission Working Capital	($411,945)	$0		$0
Company Claim [1]	($411,000)	$0	Company Claim [1]	$0
Commission Adjustment	($945)	$0		$0
Total Interest & Dividend Adj.	($945)			

[1] Company Main Brief.

Commission Final Allowance
TABLE V - Wastewater -Base
Aqua Pennsylvania Wastewater, Inc. - Base
CASH WORKING CAPITAL -TAXES
R-2021-3027385, R-2021-3027386

Description	Company Proforma Tax Expense Present Rates	Commission Adjustments	Commission Pro forma Tax Expense Present Rates	Commission Allowance	Commission Adjusted Taxes at Present Rates	Daily Expense	Net Lead/ Lag Days	Accrued Tax Adjustment
Assessments	$127,675	$0	$127,675	$104,877	$232,552	$637.13	-197.50	($125,833)
Local, County, School, & Municipal Tax	$175,853	$0	$175,853		$175,853	$481.79	-167.00	($80,459)
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
State Income Tax	($1,178,637)	$14,597	($1,164,040)	$1,531,023	$366,983	$1,005.43	45.20	$45,445
Federal Income Tax	($2,225,857)	$27,620	($2,198,237)	$2,896,852	$698,615	$1,914.01	33.40	$63,928
	($3,100,965)	$42,217	($3,058,748)	$4,532,752	$1,474,004	$4,038.36	(24.00)	($96,919)

(1) Company Main Brief

Average Lag Days in Receipt of Revenues	50.2
Average Lag in Payment of Taxes	(24.0)
Net Lag	74
Average Daily Tax Expense	4,038
Commission Cash Working Capital for Taxes	299,646
Less Company Claim (1)	73,000
Commission Adjustment	226,646

Commission Final Allowance
TABLE VI - Wastewater - Base
Aqua Pennsylvania Wastewater, Inc. - Base
CASH WORKING CAPITAL -- O & M EXPENSE
R-2021-3027385, R-2021-3027386

Description	Company Pro forma F.T.Y. Expense	Commission	Commission Pro forma Expenses	Lag Days	Lag Dollars
Hourly Labor	$1,098,103	$0	$1,098,103	7.50	$8,235,769
Non-Union Labor	$995,114	$0	$995,114	11.00	$10,946,249
Management Fee (3)	$714,262	($23,373)	$690,889	16.00	$11,054,219
Electric Power	$888,526	$0	$888,526	20.73	$18,415,943
Employee Group Insurance	$1,255,930	$0	$1,255,930	16.00	$20,094,875
Liability Insurance (4)	$23,324	$18,640	$41,964	-1.37	($57,484)
SFI Postage	$51,111	$0	$51,111	-7.96	($406,901)
All Other Expenses	$5,707,866	$0	$5,707,866	25.50	$145,550,579
General Inflation (2)	$0	($145,368)	($145,368)	19.90	($2,892,832)
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$10,734,236	($150,101)	$10,584,134	19.90	$210,940,417

Commission Average Revenue Lag	50.2	
Less: Commission Avg. Expense Lag	19.9	
Net Difference	30.3	Days
Commission Pro forma O & M Expense per Day	$28,998	
Commission CWC for O & M	$878,639	
Less: Company Claim (1)(2)	$888,000	
Commission Adjustment	($9,361)	

Notes and Sources to Accompany Table VI – Wastewater - Base

(1) Company Main Brief

(2) See Table II - Wastewater - Base, Note 2. We reject increases Aqua made to all expense accounts included in its general inflation claim. Since Exhibits 1-A to 1-G at Schedules C-4.1 and G-5.2 use different item descriptions, the number of lag days used for this adjustment is equal to the weighted average O & M Expense lag days for this rate zone after all other adjustments are applied.

(3) See Table II - Wastewater - Base, Note 1. SERP expenses are under the management fee account. OCA Exhibit LA-3 at Page 63.

(4) See Table II Wastewater - Base, Note 3.

Commission Final Allowance
TABLE I - Wastewater - Limerick
Aqua Pennsylvania Wastewater, Inc. - Limerick
INCOME SUMMARY
R-2021-3027385, R-2021-3027386

	Pro Forma Present Rates[1]	Company Adjustments [1]	Pro Forma Present Rates (Revised) [1]	Commission Adjustments	Commission Pro Forma Present Rates	Commission Revenue Increase [2]	Total Allowable Revenues
	$	$	$	$	$	$	$
Operating Revenue	$ 3,978,573	$ -	$ 3,978,573	$ -	$ 3,978,573	$ 5,581,376	$ 9,559,949
Expenses:							
O & M Expense	2,041,053	-	2,041,053	(27,778)	2,013,275	66,637	2,079,912
Depreciation	1,998,881	-	1,998,881	-	1,998,881	-	1,998,881
Taxes, Other	26,719	-	26,719	-	26,719	37,482	64,201
Income Taxes:							
State	(146,426)	-	(146,426)	2,634	(143,792)	547,178	403,386
Federal	(211,135)	-	(211,135)	4,984	(206,151)	1,035,317	829,166
Total Expenses	3,709,091	-	3,709,091	(20,160)	3,688,931	1,686,614	5,375,545
Net Inc. Available for Return	269,482	$ -	$ 269,482	$ 20,160	$ 289,642	$ 3,894,762	$ 4,184,405
Rate Base	57,744,861	-	57,744,861	76,673	57,821,534		57,821,534
Rate of Return	0.47%		0.47%		0.50%		7.23675800%

[1] Company Main Brief
[2] Revenue increases before Section 1311(c) allocation from water to wastewater

Pre-Act 11 Allocation Revenue Change (%): 140.29%

Commission Final Allowance

TABLE I(A) - Wastewater - Limerick

Aqua Pennsylvania Wastewater, Inc. - Limerick

RATE OF RETURN

R-2021-3027385, R-2021-3027386

	Structure	Cost	After-Tax Weighted Cost	Effective Tax Rate Complement	Pre-Tax Weighted Cost Rate
Total Cost of Debt			1.84216100%		1.84%
Long-term Debt	46.05%	4.00%	1.84216100%		1.84%
Short-term Debt	0.00%	0.00%	0.00000000%		0.00%
Preferred Stock	0.00%	0.00%	0.00000000%	0.711079	0.00%
Common Equity	53.95%	10.00%	5.39459700%	0.711079	7.59%
	100.00%		7.23675800% [1]		9.43%
Pre-Tax Interest Coverage	5.12				
After-Tax Interest Coverage	3.93				
Tax Rate Complement (1-(21%+(9.99% X (1-21%))	71.10790%				

[1] The Company rounded the Total After-Tax Weighted Cost to 4 decimals places. The formula in the original presentation did not round the Total After-Tax Weighted Cost.

Commission Final Allowance
Aqua Pennsylvania Wastewater, Inc. - Limerick
TABLE I(B) - Wastewater - Limerick
REVENUE FACTOR
R-2021-3027385, R-2021-3027386

100%	1.00000000
Less:	
Uncollectible Accounts Factor (*)	0.01193911
PUC, OCA, OSBA, DPC Assessment Factors (*)	0.00671560
Gross Receipts Tax	0.00000000
Other Tax Factors	0.00000000
	0.98134529
State Income Tax Rate (*)	0.09990000
Effective State Income Tax Rate	0.09803639
Factor After Local and State Taxes	0.88330890
Federal Income Tax Rate (*)	0.21000000
Effective Federal Income Tax Rate	0.18549487
Revenue Factor (100% - Effective Tax Rates)	0.69781403

(*) Company Main Brief

Commission Final Adjustments
TABLE II - Wastewater - Limerick
SUMMARY OF ADJUSTMENTS
R-2021-3027385, R-2021-3027386

Adjustments	Rate Base	Revenues	Expenses	Depreciation	Taxes-Other	State Income Tax	Federal Income Tax
	$	$	$	$	$	$	$
RATE BASE:							
CWC:							
Int. & Div. (Table IV)	(389)						
Taxes (Table V)	78,550						
O & M (Table VI)	(1,488)						
REVENUES:							
					0	0	0
EXPENSES:							
						0	0
Supp. Exec. Retire. Program [1]			(8,035)			803	1,519
General Inflation [2]			(23,275)			2,325	4,400
Gen. Liab. Insurance [3]			3,533			(353)	(668)
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
						0	0
TAXES:							
						0	0
Interest Synchronization (Table III)						(141)	(267)
TOTALS	76,673	0	(27,778)	0	0	2,634	4,984

Notes to Accompany Table II -Wastewater - Limerick

(1) Remove SERP Expenses. The OCA's $57,050 adjustment is allocated to each wastewater rate zone based on the relative percentage of management fees assigned to each rate zone per Aqua Exhibits 1-B to 1-G at Schedule C-1. Since Limerick is assigned $245,560 of $1,743,416 in total management fees, this adjustment is calculated as follows: [–$57,050 x ($245,560 / $1,743,416) = –$8,035].

(2) Remove general inflation adjustment.

(3) Adopt I&E's position regarding general liability insurance expense.

Commission Final Allowance
TABLE III - Wastewater - Limerick
Aqua Pennsylvania Wastewater, Inc. - Limerick
INTEREST SYNCHRONIZATION
R-2021-3027385, R-2021-3027386

	Amount $
Company Rate Base Claim [1]	57,744,861
Commission Rate Base Adjustments (From Table II)	76,673
Commission Rate Base (Line 1 - Line 2)	57,821,534
Weighted Cost of Debt (From Table IA)	1.84216100%
Commission Interest Expense (Line 3 x Line 4)	1,065,166
Company Claim [1]	1,063,753
Total Commission Adjustment (Line 6 - Line 5)	(1,412)
Company Adjustment [1]	0
Net Commission Interest Adjustment (Line 7 - Line 8)	(1,412)
State Income Tax Rate	9.99%
State Income Tax Adjustment (Line 9 x Line 10) (Flow to Table II)	(141)
Net Commission Interest Adjustment (Line 9)	(1,412)
State Income Tax Adjustment (Line 11)	(141)
Net Commission Adjustment for F.I.T. (Line 9 - Line 11)	(1,271)
Federal Income Tax Rate	21.00%
Federal Income Tax Adjustment (Line 12 x Line 13) (Flow to Table II)	(267)

[1] Company Main Brief

Commission Final Allowance
TABLE IV - Wastewater - Limerick
Aqua Pennsylvania Wastewater, Inc. - Limerick
CASH WORKING CAPITAL - Interest and Dividends
R-2021-3027385, R-2021-3027386

Accrued Interest	Long-Term Debt	Short-Term Debt	Preferred Stock Dividends	
Company Rate Base Claim	$57,744,861	$57,744,861	Company Rate Base Claim	$57,744,861
Commission Rate Base Adjustments	$76,673	$76,673	Commission Rate Base Adjustments	$76,673
Commission Rate Base	$57,821,534	$57,821,534	Commission Rate Base	$57,821,534
Weighted Cost of Debt	1.84216100%	0.00%	Weighted Cost Pref. Stock	0.00000000%
Commission Annual Interest Exp.	$1,065,166	$0	Commission Preferred Dividends	$0
Average Revenue Lag Days	49.7	49.7	Average Revenue Lag Days	49.7
Average Expense Lag Days	91.3	91.3	Average Expense Lag Days	91.3
Net Lag Days	-41.6	-41.6	Net Lag Days	-41.6
Working Capital Adjustment				
Commission Daily Interest Exp.	$2,918	$0	Commission Daily Dividends	$0
Net Lag Days	-41.6	-41.6	Net Lag Days	-41.6
Commission Working Capital	($121,389)	$0		$0
Company Claim [4]	($121,000)	$0	Company Claim [4]	$0
Commission Adjustment	($389)	$0		$0
Total Interest & Dividend Adj.	($389)			

[4] Company Main Brief.

Commission Final Allowance
TABLE V - Wastewater -Limerick
Aqua Pennsylvania Wastewater, Inc. - Limerick
CASH WORKING CAPITAL -TAXES
R-2021-3027385, R-2021-3027386

Description	Company Proforma Tax Expense Present Rates	Commission Adjustments	Commission Pro forma Tax Expense Present Rates	Commission Allowance	Commission Adjusted Taxes at Present Rates	Daily Expense	Net Lead/ Lag Days	Accrued Tax Adjustment
Assessments	$26,719	$0	$26,719	$37,482	$64,201	$175.89	-197.5	($34,738)
	$0	$0	$0		$0	$0.00	0.0	$0
	$0	$0	$0		$0	$0.00	0.0	$0
	$0	$0	$0		$0	$0.00	0.0	$0
	$0	$0	$0		$0	$0.00	0.0	$0
	$0	$0	$0		$0	$0.00	0.0	$0
	$0	$0	$0		$0	$0.00	0.0	$0
	$0	$0	$0		$0	$0.00	0.0	$0
	$0	$0	$0		$0	$0.00	0.0	$0
	$0	$0	$0		$0	$0.00	0.0	$0
	$0	$0	$0		$0	$0.00	0.0	$0
State Income Tax	($146,426)	$2,634	($143,792)	$547,178	$403,386	$1,105.17	45.2	$49,954
Federal Income Tax	($277,054)	$4,984	($272,070)	$1,035,317	$763,247	$2,091.09	33.4	$69,842
	($396,762)	$7,618	($389,144)	$1,619,977	$1,230,833	$3,372.15	25.22	$85,058

(1) Company Main Brief

Average Lag Days in Receipt of Revenues	49.7
Average Lag in Payment of Taxes	25.2
Net Lag	24.5
Average Daily Tax Expense	3,372
Commission Cash Working Capital for Taxes	82,550
Less Company Claim (1)	4,000
Commission Adjustment	78,550

Commission Final Allowance
TABLE VI - Wastewater - Limerick
Aqua Pennsylvania Wastewater, Inc. - Limerick
CASH WORKING CAPITAL -- O & M EXPENSE
R-2021-3027385, R-2021-3027386

Description	Company Pro forma F.T.Y. Expense	Commission	Commission Pro forma Expenses	Lag Days	Lag Dollars
Hourly Labor	$322,628	$0	$322,628	7.50	$2,419,712
Non-Union Labor	$147,980	$0	$147,980	11.00	$1,627,776
Management Fee [3]	$245,560	($8,035)	$237,524	16.00	$3,800,390
Electric Power	$249,039	$0	$249,039	20.73	$5,161,671
Employee Group Insurance	$282,365	$0	$282,365	16.00	$4,517,836
Liability Insurance [4]	$8,019	$3,533	$11,552	-1.37	($15,824)
SFI Postage	$17,572	$0	$17,572	-7.96	($139,891)
All Other Expenses	$711,728	$0	$711,728	25.50	$18,149,058
General Inflation [2]	$0	($23,275)	($23,275)	17.90	($416,629)
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$1,984,890	($27,778)	$1,957,112	17.90	$35,104,099

Commission Average Revenue Lag	49.7	
Less: Commission Avg. Expense Lag	17.9	
Net Difference	31.8	Days
Commission Pro forma O & M Expense per Day	$5,362	
Commission CWC for O & M	$170,512	
Less: Company Claim [1][2]	$172,000	
Commission Adjustment	($1,488)	

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Notes and Sources to Accompany Table VI – Wastewater - Limerick

(1) Company Main Brief

(2) See Table II - Wastewater - Limerick, Note 2. We reject increases Aqua made to all expense accounts included in its general inflation claim. Since Exhibits 1-A to 1-G at Schedules C-4.1 and G-5.2 use different item descriptions, the number of lag days used for this adjustment is equal to the weighted average O & M Expense lag days for this rate zone after all other adjustments are applied.

(3) See Table II - Wastewater - Limerick, Note 1. SERP expenses are under the management fee account. OCA Exhibit LA-3 at Page 63.

(4) See Table II - Wastewater - Limerick, Note 3.

Commission Final Allowance
TABLE I - Wastewater - East Bradford
Aqua Pennsylvania Wastewater, Inc. - East Bradford
INCOME SUMMARY
R-2021-3027385, R-2021-3027386

	Pro Forma Present Rates[1]	Company Adjustments [1]	Pro Forma Present Rates (Revised) [1]	Commission Adjustments	Commission Pro Forma Present Rates	Commission Revenue Increase [2]	Total Allowable Revenues
	$	$	$	$	$	$	$
Operating Revenue	$ 1,014,569	$ -	$ 1,014,569	$ -	$ 1,014,569	$ 777,094	$ 1,791,663
Expenses:							
O & M Expense	1,113,197	-	1,113,197	(7,802)	1,105,395	9,278	1,114,673
Depreciation	158,552	-	158,552	-	158,552	-	158,552
Taxes, Other	11,413	-	11,413	-	11,413	5,219	16,632
Income Taxes:							
State	(42,221)	-	(42,221)	761	(41,460)	76,183	34,723
Federal	(68,340)	-	(68,340)	1,441	(66,899)	144,147	77,248
Total Expenses	1,172,601	-	1,172,601	(5,600)	1,167,001	234,827	1,401,828
Net Inc. Available for Return	(158,032)	$ -	$ (158,032)	$ 5,600	$ (152,432)	$ 542,267	$ 389,835
Rate Base	5,377,205	-	5,377,205	9,669	5,386,874		5,386,874
Rate of Return	-2.94%		-2.94%		-2.83%		7.23675800%

[1] Company Main Brief
[2] Revenue increases before Section 1311(c) allocation from water to wastewater

Pre-Act 11 Allocation Revenue Change (%): 76.59%

Commission Final Allowance
TABLE I(A) - Wastewater - East Bradford
Aqua Pennsylvania Wastewater, Inc. - East Bradford
RATE OF RETURN
R-2021-3027385, R-2021-3027386

	Structure	Cost	After-Tax Weighted Cost	Effective Tax Rate Complement	Pre-Tax Weighted Cost Rate
Total Cost of Debt			1.84216100%		1.84%
Long-term Debt	46.05%	4.00%	1.84216100%		1.84%
Short-term Debt	0.00%	0.00%	0.00000000%		0.00%
Preferred Stock	0.00%	0.00%	0.00000000%	0.711079	0.00%
Common Equity	53.95%	10.00%	5.39459700%	0.711079	7.59%
	100.00%		7.23675800%		9.43%
Pre-Tax Interest Coverage	5.12				
After-Tax Interest Coverage	3.93				
Tax Rate Complement (1-(21%+(9.99% X (1-21%))	71.10790%				

Commission Final Allowance
Aqua Pennsylvania Wastewater, Inc. - East Bradford
TABLE I(B) - Wastewater - East Bradford
REVENUE FACTOR
R-2021-3027385, R-2021-3027386

100%	1.00000000
Less:	
Uncollectible Accounts Factor (*)	0.01193911
PUC, OCA, OSBA, DPC Assessment Factors (*)	0.00671560
Gross Receipts Tax	0.00000000
Other Tax Factors	0.00000000
	0.98134529
State Income Tax Rate (*)	0.09990000
Effective State Income Tax Rate	0.09803639
Factor After Local and State Taxes	0.88330890
Federal Income Tax Rate (*)	0.21000000
Effective Federal Income Tax Rate	0.18549487
Revenue Factor (100% - Effective Tax Rates)	0.69781403

(*) Company Main Brief

Commission Final Adjustments
TABLE II - Wastewater - East Bradford
SUMMARY OF ADJUSTMENTS
R-2021-3027385, R-2021-3027386

Adjustments	Rate Base	Revenues	Expenses	Depreciation	Taxes-Other	State Income Tax	Federal Income Tax
	\$	\$	\$	\$	\$	\$	\$
RATE BASE:							
CWC:							
Int. & Div. (Table IV)	250						
Taxes (Table V)	9,729						
O & M (Table VI)	(310)						
REVENUES:							
					0	0	0
EXPENSES:							
						0	0
Supp. Exec. Retire. Program [1]			(1,763)			176	333
General Inflation [2]			(6,828)			682	1,291
Gen. Liab. Insurance [3]			789			(79)	(149)
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
						0	0
TAXES:							
						0	0
Interest Synchronization (Table III)						(18)	(34)
TOTALS	9,669	0	(7,802)	0	0	761	1,441

Notes and Sources to Accompany Table II – Wastewater – East Bradford

(1) Remove SERP Expenses. The OCA's $57,050 adjustment is allocated to each wastewater rate zone based on the relative percentage of management fees assigned to each rate zone per Aqua Exhibits 1-B to 1-G at Schedule C-2. Since East Bradford is assigned $53,881 of $1,743,416 in total management fees, this adjustment is calculated as follows: [–$57,050 x ($53,881 / $1,743,416) = –$1,763].

(2) Remove general inflation adjustment.

(3) Adopt I&E's position regarding general liability insurance expense.

Commission Final Allowance
TABLE III - Wastewater -East Bradford
Aqua Pennsylvania Wastewater, Inc. - East Bradford
INTEREST SYNCHRONIZATION
R-2021-3027385, R-2021-3027386

	Amount $
Company Rate Base Claim [1]	5,377,205
Commission Rate Base Adjustments (From Table II)	9,669
Commission Rate Base (Line 1 - Line 2)	5,386,874
Weighted Cost of Debt (From Table IA)	1.84216100%
Commission Interest Expense (Line 3 x Line 4)	99,235
Company Claim [1]	99,057
Total Commission Adjustment (Line 6 - Line 5)	(178)
Company Adjustment [1]	0
Net Commission Interest Adjustment (Line 7 - Line 8)	(178)
State Income Tax Rate	9.99%
State Income Tax Adjustment (Line 9 x Line 10) (Flow to Table II)	(18)
Net Commission Interest Adjustment (Line 9)	(178)
State Income Tax Adjustment (Line 11)	(18)
Net Commission Adjustment for F.I.T. (Line 9 - Line 11)	(160)
Federal Income Tax Rate	21.00%
Federal Income Tax Adjustment (Line 12 x Line 13) (Flow to Table II)	(34)

[1] Company Main Brief

Commission Final Allowance
TABLE IV - Wastewater - East Bradford
Aqua Pennsylvania Wastewater, Inc. - East Bradford
CASH WORKING CAPITAL - Interest and Dividends
R-2021-3027385, R-2021-3027386

Accrued Interest	Long-Term Debt	Short-Term Debt	Preferred Stock Dividends	
Company Rate Base Claim	$5,377,205	$5,377,205	Company Rate Base Claim	$5,377,205
Commission Rate Base Adjustments	$9,669	$9,669	Commission Rate Base Adjustments	$9,669
Commission Rate Base	$5,386,874	$5,386,874	Commission Rate Base	$5,386,874
Weighted Cost of Debt	1.84216100%	0.00%	Weighted Cost Pref. Stock	0.00000000%
Commission Annual Interest Exp.	$99,235	$0	Commission Preferred Dividends	$0
Average Revenue Lag Days	48.1	48.1	Average Revenue Lag Days	48.1
Average Expense Lag Days	91.3	91.3	Average Expense Lag Days	91.3
Net Lag Days	-43.2	-43.2	Net Lag Days	-43.2
Working Capital Adjustment				
Commission Daily Interest Exp.	$272	$0	Commission Daily Dividends	$0
Net Lag Days	-43.2	-43.2	Net Lag Days	-43.2
Commission Working Capital	($11,750)	$0		$0
Company Claim [1]	($12,000)	$0	Company Claim [1]	$0
Commission Adjustment	$250	$0		$0
Total Interest & Dividend Adj.	$250			

[1] Company Main Brief.

Commission Final Allowance
TABLE V - Wastewater -East Bradford
Aqua Pennsylvania Wastewater, Inc. - East Bradford
CASH WORKING CAPITAL -TAXES
R-2021-3027385, R-2021-3027386

Description	Company Proforma Tax Expense Present Rates	Commission Adjustments	Commission Pro forma Tax Expense Present Rates	Commission Allowance	Commission Adjusted Taxes at Present Rates	Daily Expense	Net Lead/ Lag Days	Accrued Tax Adjustment
PA PUC - General Assessments	$6,813	$0	$6,813	$5,219	$12,032	$32.97	-197.50	($6,512)
Local, County, School, & Municipal Tax	$4,600	$0	$4,600		$4,600	$12.60	-167.00	($2,104)
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
State Income Tax	($42,221)	$761	($41,460)	$76,183	$34,723	$95.13	45.20	$4,300
Federal Income Tax	($79,886)	$1,441	($78,445)	$144,147	$65,702	$180.00	33.40	$6,012
	($110,694)	$2,202	($108,492)	$225,549	$117,057	$320.70	5.29	$1,696

(1) Company Main Brief

Average Lag Days in Receipt of Revenues	48
Average Lag in Payment of Taxes	5.3
Net Lag	42.8
Average Daily Tax Expense	321
Commission Cash Working Capital for Taxes	13,729
Less Company Claim (1)	4,000
Commission Adjustment	9,729

Commission Final Allowance
TABLE VI - Wastewater - East Bradford
Aqua Pennsylvania Wastewater, Inc. - East Bradford
CASH WORKING CAPITAL -- O & M EXPENSE
R-2021-3027385, R-2021-3027386

Description	Company Pro forma F.T.Y. Expense	Commission	Commission Pro forma Expenses	Lag Days	Lag Dollars
Non-Union Labor	$161	$0	$161	11.00	$1,775
Management Fee (3)	$53,881	($1,763)	$52,118	16.00	$833,889
Electric Power	$12,168	$0	$12,168	20.73	$252,196
Employee Group Insurance	$97	$0	$97	16.00	$1,549
Liability Insurance (4)	$1,760	$789	$2,549	-1.37	($3,491)
SFI Postage	$3,856	$0	$3,856	-7.96	($30,698)
All Other Expenses	$1,027,433	$0	$1,027,433	25.50	$26,199,540
General Inflation (2)	$0	($6,828)	($6,828)	24.80	($169,337)
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$1,099,356	($7,802)	$1,091,553	24.80	$27,085,423

Commission Average Revenue Lag	48.1	
Less: Commission Avg. Expense Lag	24.8	
Net Difference	23.3	Days
Commission Pro forma O & M Expense per Day	$2,991	
Commission CWC for O & M	$69,690	
Less: Company Claim (1)(2)	$70,000	
Commission Adjustment	($310)	

Notes and Sources to Accompany Table VI – Wastewater – East Bradford

(1) Company Main Brief

(2) See Table II - Wastewater - East Bradford, Note 2. We reject increases Aqua made to all expense accounts included in its general inflation claim. Since Exhibits 1-A to 1-G at Schedules C-4.1 and G-5.2 use different item descriptions, the number of lag days used for this adjustment is equal to the weighted average O & M Expense lag days for this rate zone after all other adjustments are applied.

(3) See Table II - Wastewater East Bradford, Note 1. SERP expenses are under the management fee account. OCA Exhibit LA-3 at Page 63.

(4) See Table II - Wastewater E Bradford, Note 3.

Commission Final Allowance

TABLE I - Wastewater - Cheltenham

Aqua Pennsylvania Wastewater, Inc. - Cheltenham

INCOME SUMMARY

R-2021-3027385, R-2021-3027386

	Pro Forma Present Rates[1]	Company Adjustments [1]	Pro Forma Present Rates (Revised) [1]	Commission Adjustments	Commission Pro Forma Present Rates	Commission Revenue Increase [2]	Total Allowable Revenues
	$	$	$	$	$	$	$
Operating Revenue	$ 7,258,740	$ -	$ 7,258,740	$ -	$ 7,258,740	$ 2,752,399	$ 10,011,139
Expenses:							
O & M Expense	4,552,450	-	4,552,450	(16,469)	4,535,981	32,861	4,568,842
Depreciation	1,011,770	-	1,011,770	-	1,011,770	-	1,011,770
Taxes, Other	48,747	-	48,747	-	48,747	18,484	67,231
Income Taxes:							
State	(10,260)	-	(10,260)	1,545	(8,715)	269,835	261,120
Federal	164,955	-	164,955	2,924	167,879	510,556	678,435
Total Expenses	5,767,661	-	5,767,661	(12,000)	5,755,662	831,736	6,587,398
Net Inc. Available for Return	1,491,079	$ -	$ 1,491,079	$ 12,000	$ 1,503,078	$ 1,920,663	$ 3,423,741
Rate Base	47,256,177	-	47,256,177	54,249	47,310,426		47,310,426
Rate of Return	3.16%		3.16%		3.18%		7.23675800%

[1] Company Main Brief

[2] Revenue increases before Section 1311(c) allocation from water to wastewater

Pre-Act 11 Allocation Revenue Change (%): 37.92%

Commission Final Allowance
TABLE I(A) - Wastewater - Cheltenham
Aqua Pennsylvania Wastewater, Inc. - Cheltenham
RATE OF RETURN
R-2021-3027385, R-2021-3027386

	Structure	Cost	After-Tax Weighted Cost	Effective Tax Rate Complement	Pre-Tax Weighted Cost Rate
Total Cost of Debt			1.84216100%		1.84%
Long-term Debt	46.05%	4.00%	1.84216100%		1.84%
Short-term Debt	0.00%	0.00%	0.00000000%		0.00%
Preferred Stock	0.00%	0.00%	0.00000000%	0.711079	0.00%
Common Equity	53.95%	10.00%	5.39459700%	0.711079	7.59%
	100.00%		7.23675800%		9.43%
Pre-Tax Interest Coverage	5.12				
After-Tax Interest Coverage	3.93				
Tax Rate Complement (1-(21%+(9.99% X (1-21%))	71.10790%				

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Commission Final Allowance
Aqua Pennsylvania Wastewater, Inc. - Cheltenham
TABLE I(B) - Wastewater - Cheltenham
REVENUE FACTOR
R 2021 3027385, R 2021 3027386

100%	1.00000000
Less:	
Uncollectible Accounts Factor (*)	0.01193911
PUC, OCA, OSBA, DPC Assessment Factors (*)	0.00671560
Gross Receipts Tax	0.00000000
Other Tax Factors	0.00000000
	0.98134529
State Income Tax Rate (*)	0.09990000
Effective State Income Tax Rate	0.09803639
Factor After Local and State Taxes	0.88330890
Federal Income Tax Rate (*)	0.21000000
Effective Federal Income Tax Rate	0.18549487
Revenue Factor (100% - Effective Tax Rates)	0.69781403

(*) Company Main Brief

Commission Final Adjustments
TABLE II - Wastewater - Cheltenham
SUMMARY OF ADJUSTMENTS
R-2021-3027385, R-2021-3027386

Adjustments	Rate Base	Revenues	Expenses	Depreciation	Taxes-Other	State Income Tax	Federal Income Tax
	$	$	$	$	$	$	$
RATE BASE:							
CWC:							
Int. & Div. (Table IV)	(431)						
Taxes (Table V)	56,325						
O & M (Table VI)	(1,645)						
REVENUES:							
					0	0	0
EXPENSES:							
						0	0
Supp. Exec. Retire. Program [1]			(14,049)			1,403	2,656
General Inflation [2]			(8,719)			871	1,648
Gen. Liab. Insurance [3]			6,299			(629)	(1,191)
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
						0	0
TAXES:							
						0	0
Interest Synchronization (Table III)						(100)	(189)
TOTALS	54,249	0	(16,469)	0	0	1,545	2,924

Notes and Sources to Accompany Table II – Wastewater - Cheltenham

(1) Remove SERP Expenses. The OCA's $57,050 adjustment is allocated to each wastewater rate zone based on the relative percentage of management fees assigned to each rate zone per Aqua Exhibits 1-B to 1-G at Schedule C-1. Since Cheltenham is assigned $429,319 of $1,743,416 in total management fees, this adjustment is calculated as follows: [–$57,050 x ($429,319 / $1,743,416) = –$14,049].

(2) Remove general inflation adjustment.

(3) Adopt I&E's position regarding general liability insurance expense.

Commission Final Allowance
TABLE III - Wastewater -Cheltenham
Aqua Pennsylvania Wastewater, Inc. - Cheltenham
INTEREST SYNCHRONIZATION
R-2021-3027385, R-2021-3027386

	Amount $
Company Rate Base Claim [1]	47,256,177
Commission Rate Base Adjustments (From Table II)	54,249
Commission Rate Base (Line 1 - Line 2)	47,310,426
Weighted Cost of Debt (From Table IA)	1.84216100%
Commission Interest Expense (Line 3 x Line 4)	871,534
Company Claim [1]	870,535
Total Commission Adjustment (Line 6 - Line 5)	(999)
Company Adjustment [1]	0
Net Commission Interest Adjustment (Line 7 - Line 8)	(999)
State Income Tax Rate	9.99%
State Income Tax Adjustment (Line 9 x Line 10) (Flow to Table II)	(100)
Net Commission Interest Adjustment (Line 9)	(999)
State Income Tax Adjustment (Line 11)	(100)
Net Commission Adjustment for F.I.T. (Line 9 - Line 11)	(899)
Federal Income Tax Rate	21.00%
Federal Income Tax Adjustment (Line 12 x Line 13) (Flow to Table II)	(189)

[1] Company Main Brief

Commission Final Allowance
TABLE IV - Wastewater - Cheltenham
Aqua Pennsylvania Wastewater, Inc. - Cheltenham
CASH WORKING CAPITAL - Interest and Dividends
R-2021-3027385, R-2021-3027386

Accrued Interest	Long-Term Debt	Short-Term Debt	Preferred Stock Dividends	
Company Rate Base Claim	$47,256,177	$47,256,177	Company Rate Base Claim	$47,256,177
Commission Rate Base Adjustments	$54,249	$54,249	Commission Rate Base Adjustments	$54,249
Commission Rate Base	$47,310,426	$47,310,426	Commission Rate Base	$47,310,426
Weighted Cost of Debt	1.84216100%	0.00%	Weighted Cost Pref. Stock	0.00000000%
Commission Annual Interest Exp.	$871,534	$0	Commission Preferred Dividends	$0
Average Revenue Lag Days	57.2	57.2	Average Revenue Lag Days	57.2
Average Expense Lag Days	91.3	91.3	Average Expense Lag Days	91.3
Net Lag Days	-34.1	-34.1	Net Lag Days	-34.1
Working Capital Adjustment				
Commission Daily Interest Exp.	$2,388	$0	Commission Daily Dividends	$0
Net Lag Days	-34.1	-34.1	Net Lag Days	-34.1
Commission Working Capital	($81,431)	$0		$0
Company Claim [1]	($81,000)	$0	Company Claim [1]	$0
Commission Adjustment	($431)	$0		$0
Total Interest & Dividend Adj.	($431)			

[1] Company Main Brief.

Commission Final Allowance
TABLE V - Wastewater -Cheltenham
Aqua Pennsylvania Wastewater, Inc. - Cheltenham
CASH WORKING CAPITAL -TAXES
R-2021-3027385, R-2021-3027386

Description	Company Proforma Tax Expense Present Rates	Commission Adjustments	Commission Pro forma Tax Expense Present Rates	Commission Allowance	Commission Adjusted Taxes at Present Rates	Daily Expense	Net Lead/ Lag Days	Accrued Tax Adjustment
PA PUC - General Assessments	$48,747	$0	$48,747	$18,484	$67,231	$184.19	-197.50	($36,378)
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
	$0	$0	$0		$0	$0.00	0.00	$0
State Income Tax	($10,260)	$1,545	($8,715)	$269,835	$261,120	$715.40	45.20	$32,336
Federal Income Tax	($19,413)	$2,924	($16,489)	$510,556	$494,067	$1,353.61	33.40	$45,211
	$19,073	$4,469	$23,542	$798,875	$822,417	$2,253.20	18.00	$41,169

[1] Company Main Brief

Average Lag Days in Receipt of Revenues	57.2
Average Lag in Payment of Taxes	18.0
Net Lag	39.2
Average Daily Tax Expense	2,253
Commission Cash Working Capital for Taxes	88,325
Less Company Claim [1]	32,000
Commission Adjustment	56,325

Commission Final Allowance
TABLE VI - Wastewater - Cheltenham
Aqua Pennsylvania Wastewater, Inc. - Cheltenham
CASH WORKING CAPITAL -- O & M EXPENSE
R-2021-3027385, R-2021-3027386

Description	Company Pro forma F.T.Y. Expense	Commission	Commission Pro forma Expenses	Lag Days	Lag Dollars
Hourly Labor	$55,850	$0	$55,850	7.50	$418,878
Non-Union Labor	$309,953	$0	$309,953	11.00	$3,409,478
Management Fee (3)	$429,319	($14,049)	$415,270	16.00	$6,644,319
Employee Group Insurance	$219,482	$0	$219,482	16.00	$3,511,709
Liability Insurance (4)	$14,020	$6,299	$20,319	-1.37	($27,833)
SFI Postage	$30,721	$0	$30,721	-7.96	($244,571)
All Other Expenses	$3,391,357	$0	$3,391,357	25.50	$86,479,591
General Inflation (2)	$0	($8,719)	($8,719)	22.60	($197,047)
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$4,450,701	($16,469)	$4,434,232	22.60	$99,994,524

Commission Average Revenue Lag	57.2	
Less: Commission Avg. Expense Lag	22.6	
Net Difference	34.6	Days
Commission Pro forma O & M Expense per Day	$12,149	
Commission CWC for O & M	$420,355	
Less: Company Claim (1)(2)	$422,000	
Commission Adjustment	($1,645)	

Notes and Sources to Accompany Table VI – Wastewater – Cheltenham

(1) Company Main Brief

(2) See Table II - Wastewater Cheltenham, Note 2. We reject increases Aqua made to all expense accounts included in its general inflation claim. Since Exhibits 1-A to 1-G at Schedules C-4.1 and G-5.2 use different item descriptions, the number of lag days used for this adjustment is equal to the weighted average O & M Expense lag days for this rate zone after all other adjustments are applied.

(3) See Table II - Wastewater Cheltenham, Note 1. SERP expenses are under the management fee account. OCA Exhibit LA-3 at Page 63.

(4) See Table II - Wastewater Cheltenham, Note 3.

Commission Final Allowance

TABLE I - Wastewater - East Norriton

Aqua Pennsylvania Wastewater, Inc. - East Norriton

INCOME SUMMARY

R-2021-3027385, R-2021-3027386

	Pro Forma Present Rates[1]	Company Adjustments [1]	Pro Forma Present Rates (Revised) [1]	Commission Adjustments	Commission Pro Forma Present Rates	Commission Revenue Increase [2]	Total Allowable Revenues
	$	$	$	$	$	$	$
Operating Revenue	$ 2,923,770	$ -	$ 2,923,770	$ -	$ 2,923,770	$ 2,739,266	$ 5,663,036
Expenses:							
O & M Expense	2,271,778	-	2,271,778	(14,318)	2,257,460	32,704	2,290,164
Depreciation	952,641	-	952,641	-	952,641	-	952,641
Taxes, Other	19,635	-	19,635	-	19,635	18,396	38,031
Income Taxes:							
State	(84,197)	-	(84,197)	1,386	(82,811)	268,548	185,737
Federal	(147,480)	-	(147,480)	2,621	(144,859)	508,120	363,261
Total Expenses	3,012,378	-	3,012,378	(10,311)	3,002,066	827,768	3,829,834
Net Inc. Available for Return	$ (88,608)	$ -	$ (88,608)	$ 10,311	$ (78,297)	$ 1,911,498	$ 1,833,202
Rate Base	25,307,104	-	25,307,104	24,706	25,331,810		25,331,810
Rate of Return	-0.35%		-0.35%		-0.31%		7.23675800%

[1] Company Main Brief

[2] Revenue increases before Section 1311(c) allocation from water to wastewater

Pre-Act 11 Allocation Revenue Change (%): 93.69%

Commission Final Allowance
TABLE I(A) - Wastewater - East Norriton
Aqua Pennsylvania Wastewater, Inc. - East Norriton
RATE OF RETURN
R-2021-3027385, R-2021-3027386

	Structure	Cost	After-Tax Weighted Cost	Effective Tax Rate Complement	Pre-Tax Weighted Cost Rate
Total Cost of Debt			1.84216100%		1.84%
Long-term Debt	46.05%	4.00%	1.84216100%		1.84%
Short-term Debt	0.00%	0.00%	0.00000000%		0.00%
Preferred Stock	0.00%	0.00%	0.00000000%	0.711079	0.00%
Common Equity	53.95%	10.00%	5.39459700%	0.711079	7.59%
	100.00%		7.23675800%		9.43%
Pre-Tax Interest Coverage	5.12				
After-Tax Interest Coverage	3.93				
Tax Rate Complement (1-(21%+(9.99% X (1-21%))	71.10790%				

Commission Final Allowance
Aqua Pennsylvania Wastewater, Inc. - East Norriton
TABLE I(B) - Wastewater - East Norriton
REVENUE FACTOR
R-2021-3027385, R-2021-3027386

100%	1.00000000
Less:	
Uncollectible Accounts Factor (*)	0.01193911
PUC, OCA, OSBA, DPC Assessment Factors (*)	0.00671560
Gross Receipts Tax	0.00000000
Other Tax Factors	0.00000000
	0.98134529
State Income Tax Rate (*)	0.09990000
Effective State Income Tax Rate	0.09803639
Factor After Local and State Taxes	0.88330890
Federal Income Tax Rate (*)	0.21000000
Effective Federal Income Tax Rate	0.18549487
Revenue Factor (100% - Effective Tax Rates)	0.69781403

(*) Company Main Brief

Commission Final Adjustments
TABLE II - Wastewater - East Norriton
SUMMARY OF ADJUSTMENTS
R-2021-3027385, R-2021-3027386

Adjustments	Rate Base	Revenues	Expenses	Depreciation	Taxes-Other	State Income Tax	Federal Income Tax
	$	$	$	$	$	$	$
RATE BASE:							
CWC:							
Int. & Div. (Table IV)	(369)						
Taxes (Table V)	25,827						
O & M (Table VI)	(752)						
REVENUES:							
					0	0	0
EXPENSES:							
						0	0
Supp. Exec. Retire. Program [1]			(7,036)			703	1,330
General Inflation [2]			(8,665)			866	1,638
Gen. Liab. Insurance [3]			1,382			(138)	(261)
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
						0	0
TAXES:							
						0	0
Interest Synchronization (Table III)						(45)	(86)
TOTALS	24,706	0	(14,318)	0	0	1,386	2,621

Notes and Sources to Accompany Table II – Wastewater – East Norriton

(1) Remove SERP Expenses. The OCA's $57,050 adjustment is allocated to each wastewater rate zone based on the relative percentage of management fees assigned to each rate zone per Aqua Exhibits 1-B to 1-G at Schedule C-1. Since East Norriton is assigned $215,006 of $1,743,416 in total management fees, this adjustment is calculated as follows:
[–$57,050 x ($215,006 / $1,743,416) = –$7,036].

(2) Remove general inflation adjustment.

(3) Adopt I&E's position regarding general liability insurance expense.

Commission Final Allowance
TABLE III - Wastewater -East Norriton
Aqua Pennsylvania Wastewater, Inc. - East Norriton
INTEREST SYNCHRONIZATION
R-2021-3027385, R-2021-3027386

	Amount $
Company Rate Base Claim [1]	25,307,104
Commission Rate Base Adjustments (From Table II)	24,706
Commission Rate Base (Line 1 - Line 2)	25,331,810
Weighted Cost of Debt (From Table IA)	1.84216100%
Commission Interest Expense (Line 3 x Line 4)	466,653
Company Claim [1]	466,198
Total Commission Adjustment (Line 6 - Line 5)	(455)
Company Adjustment [1]	0
Net Commission Interest Adjustment (Line 7 - Line 8)	(455)
State Income Tax Rate	9.99%
State Income Tax Adjustment (Line 9 x Line 10) (Flow to Table II)	(45)
Net Commission Interest Adjustment (Line 9)	(455)
State Income Tax Adjustment (Line 11)	(45)
Net Commission Adjustment for F.I.T. (Line 9 - Line 11)	(410)
Federal Income Tax Rate	21.00%
Federal Income Tax Adjustment (Line 12 x Line 13) (Flow to Table II)	(86)

[1] Company Main Brief

Commission Final Allowance
TABLE IV - Wastewater - East Norriton
Aqua Pennsylvania Wastewater, Inc. - East Norriton
CASH WORKING CAPITAL - Interest and Dividends
R-2021-3027385, R-2021-3027386

Accrued Interest	Long-Term Debt	Short-Term Debt	Preferred Stock Dividends	
Company Rate Base Claim	$25,307,104	$25,307,104	Company Rate Base Claim	$25,307,104
Commission Rate Base Adjustments	$24,706	$24,706	Commission Rate Base Adjustments	$24,706
Commission Rate Base	$25,331,810	$25,331,810	Commission Rate Base	$25,331,810
Weighted Cost of Debt	1.84216100%	0.00%	Weighted Cost Pref. Stock	0.00000000%
Commission Annual Interest Exp.	$466,653	$0	Commission Preferred Dividends	$0
Average Revenue Lag Days	44.1	44.1	Average Revenue Lag Days	44.1
Average Expense Lag Days	91.3	91.3	Average Expense Lag Days	91.3
Net Lag Days	-47.2	-47.2	Net Lag Days	-47.2
Working Capital Adjustment				
Commission Daily Interest Exp.	$1,279	$0	Commission Daily Dividends	$0
Net Lag Days	-47.2	-47.2	Net Lag Days	-47.2
Commission Working Capital	($60,369)	$0		$0
Company Claim [1]	($60,000)	$0	Company Claim [1]	$0
Commission Adjustment	($369)	$0		$0
Total Interest & Dividend Adj.	($369)			

[1] Company Main Brief.

Commission Final Allowance
TABLE V - Wastewater -East Norriton
Aqua Pennsylvania Wastewater, Inc. - East Norriton
CASH WORKING CAPITAL -TAXES
R-2021-3027385, R-2021-3027386

Description	Company Proforma Tax Expense Present Rates	Commission Adjustments	Commission Pro forma Tax Expense Present Rates	Commission Allowance	Commission Adjusted Taxes at Present Rates	Daily Expense	Net Lead/ Lag Days	Accrued Tax Adjustment
PA PUC - General Assessments	$19,635	$0	$19,635	$18,396	$38,031	$104	-197.50	($20,578)
	$0	$0	$0		$0	$0	0.00	$0
	$0	$0	$0		$0	$0	0.00	$0
	$0	$0	$0		$0	$0	0.00	$0
	$0	$0	$0		$0	$0	0.00	$0
	$0	$0	$0		$0	$0	0.00	$0
	$0	$0	$0		$0	$0	0.00	$0
	$0	$0	$0		$0	$0	0.00	$0
	$0	$0	$0		$0	$0	0.00	$0
	$0	$0	$0		$0	$0	0.00	$0
	$0	$0	$0		$0	$0	0.00	$0
State Income Tax	($84,197)	$1,386	($82,811)	$268,548	$185,737	$509	45.20	$23,001
Federal Income Tax	($159,309)	$2,621	($156,688)	$508,120	$351,432	$963	33.40	$32,159
	($223,871)	$4,007	($219,864)	$795,064	$575,200	$1,576	21.94	$34,582

(1) Company Main Brief

Average Lag Days in Receipt of Revenues	44.1
Average Lag in Payment of Taxes	22.0
Net Lag	22.1
Average Daily Tax Expense	1,576
Commission Cash Working Capital for Taxes	34,827
Less Company Claim (1)	9,000
Commission Adjustment	25,827

Commission Final Allowance
TABLE VI - Wastewater - East Norriton
Aqua Pennsylvania Wastewater, Inc. - East Norriton
CASH WORKING CAPITAL -- O & M EXPENSE
R-2021-3027385, R-2021-3027386

Description	Company Pro forma F.T.Y. Expense	Commission	Commission Pro forma Expenses	Lag Days	Lag Dollars
Non-Union Labor	$137,423	$0	$137,423	11.00	$1,511,649
Management Fee (3)	$215,006	$0	$215,006	16.00	$3,440,089
Electric Power	$122,439	($7,036)	$115,403	20.73	$2,391,894
Employee Group Insurance	$82,454	$0	$82,454	16.00	$1,319,257
Liability Insurance (4)	$7,021	$1,382	$8,403	-1.37	($11,511)
SFI Postage	$15,385	$0	$15,385	-7.96	($122,481)
All Other Expenses	$1,649,556	$0	$1,649,556	25.50	$42,063,673
General Inflation (2)	$0	($8,665)	($8,665)	22.80	($197,551)
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$2,229,283	($14,318)	$2,214,964	22.80	$50,395,019

Commission Average Revenue Lag	44.1	
Less: Commission Avg. Expense Lag	22.8	
Net Difference	21.3	Days
Commission Pro forma O & M Expense per Day	$6,068	
Commission CWC for O & M	$129,248	
Less: Company Claim (1)(2)	$130,000	
Commission Adjustment	($752)	

Notes and Sources to Accompany Table VI – Wastewater – East Norriton

(1) Company Main Brief

(2) See Table II Wastewater - East Norriton, Note 2. Reject increases Aqua made to all expense accounts included in its general inflation claim. Since Exhibits 1-A to 1-G at Schedules C-4.1 and G-5.2 use different item descriptions, the number of lag days used for this adjustment is equal to the weighted average O & M Expense lag days for this rate zone after all other adjustments are applied.

(3) See Table II Wastewater - East Norriton, Note 1. SERP expenses are under the management fee account. OCA Exhibit LA-3 at Page 63.

(4) See Table II Wastewater East Norriton, Note 3.

Commission Final Allowance
TABLE I - Wastewater - New Garden
Aqua Pennsylvania Wastewater, Inc. - New Garden
INCOME SUMMARY
R-2021-3027385, R-2021-3027386

	Pro Forma Present Rates[1]	Company Adjustments [1]	Pro Forma Present Rates (Revised) [1]	Commission Adjustments	Commission Pro Forma Present Rates	Commission Revenue Increase [2]	Total Allowable Revenues
	$	$	$	$	$	$	$
Operating Revenue	$ 2,889,080	$ -	$ 2,889,080	$ -	$ 2,889,080	$ 2,538,455	$ 5,427,536
Expenses:							
O & M Expense	1,845,024	-	1,845,024	(16,175)	1,828,849	30,307	1,859,156
Depreciation	735,834	-	735,834	-	735,834	-	735,834
Taxes, Other	19,402	-	19,402	-	19,402	17,047	36,449
Income Taxes:							
State	(75,351)	-	(75,351)	1,651	(73,700)	248,861	175,161
Federal	(40,533)	-	(40,533)	3,124	(37,409)	470,870	433,461
Total Expenses	2,484,377	-	2,484,377	(11,400)	2,472,977	767,085	3,240,062
Net Inc. Available for Return	$ 404,704	$ -	$ 404,704	$ 11,400	$ 416,104	$ 1,771,370	$ 2,187,473
Rate Base	30,246,226	-	30,246,226	(18,970)	30,227,256		30,227,256
Rate of Return	1.34%		1.34%		1.38%		7.23675800%

[1] Company Main Brief
[2] Revenue increases before Section 1311(c) allocation from water to wastewater

Pre-Act 11 Allocation Revenue Change (%): 87.86%

Commission Final Allowance
TABLE I(A) - Wastewater - New Garden
Aqua Pennsylvania Wastewater, Inc. - New Garden
RATE OF RETURN
R-2021-3027385, R-2021-3027386

	Structure	Cost	After-Tax Weighted Cost	Effective Tax Rate Complement	Pre-Tax Weighted Cost Rate
Total Cost of Debt			1.84216100%		1.84%
Long-term Debt	46.05%	4.00%	1.84216100%		1.84%
Short-term Debt	0.00%	0.00%	0.00000000%		0.00%
Preferred Stock	0.00%	0.00%	0.00000000%	0.711079	0.00%
Common Equity	53.95%	10.00%	5.39459700%	0.711079	7.59%
	100.00%		7.23675800%		9.43%
Pre-Tax Interest Coverage	5.12				
After-Tax Interest Coverage	3.93				
Tax Rate Complement (1-(21%+(9.99% X (1-21%))	71.10790%				

Commission Final Allowance
Aqua Pennsylvania Wastewater, Inc. - New Garden
TABLE I(B) - Wastewater - New Garden
REVENUE FACTOR
R-2021-3027385, R-2021-3027386

100%	1.00000000
Less:	
Uncollectible Accounts Factor (*)	0.01193911
PUC, OCA, OSBA, DFC Assessment Factors (*)	0.00671560
Gross Receipts Tax	0.00000000
Other Tax Factors	0.00000000
	0.98134529
State Income Tax Rate (*)	0.09990000
Effective State Income Tax Rate	0.09803639
Factor After Local and State Taxes	0.88330890
Federal Income Tax Rate (*)	0.21000000
Effective Federal Income Tax Rate	0.18549487
Revenue Factor (100% - Effective Tax Rates)	0.69781403

(*) Company Main Brief

Commission Final Adjustments
TABLE II - Wastewater - New Garden
SUMMARY OF ADJUSTMENTS
R-2021-3027385, R-2021-3027386

Adjustments	Rate Base	Revenues	Expenses	Depreciation	Taxes-Other	State Income Tax	Federal Income Tax
	$	$	$	$	$	$	$
RATE BASE:							
CWC:							
Int. & Div. (Table IV)	(378)						
Taxes (Table V)	(18,230)						
O & M (Table VI)	(362)						
REVENUES:							
					0	0	0
EXPENSES:							
						0	0
Supp. Exec. Retire. Program [1]			(2,794)			279	528
General Inflation [2]			(12,705)			1,269	2,402
Gen. Liab. Insurance [3]			(676)			68	128
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
			0			0	0
						0	0
TAXES:							
						0	0
Interest Synchronization (Table III)						35	66
TOTALS	(18,970)	0	(16,175)	0	0	1,651	3,124

Notes and Sources to Accompany Table II – Wastewater – New Garden

(1) Remove SERP Expenses. The OCA's $57,050 adjustment is allocated to each wastewater rate zone based on the relative percentage of management fees assigned to each rate zone per Aqua Exhibits 1-B to 1-G at Schedule C-1. Since New Garden is assigned $85,388 of $1,743,416 in total management fees, this adjustment is calculated as follows: [–$57,050 x ($85,388 / $1,743,416) = –$2,794].

(2) Remove general inflation adjustment.

(3) Adopt I&E's position regarding general liability insurance expense.

Commission Final Allowance
TABLE III - Wastewater -New Garden
Aqua Pennsylvania Wastewater, Inc. - New Garden
INTEREST SYNCHRONIZATION
R-2021-3027385, R-2021-3027386

	Amount $
Company Rate Base Claim [1]	30,246,226
Commission Rate Base Adjustments (From Table II)	(18,970)
Commission Rate Base (Line 1 - Line 2)	30,227,256
Weighted Cost of Debt (From Table IA)	1.84216100%
Commission Interest Expense (Line 3 x Line 4)	556,835
Company Claim [1]	557,184
Total Commission Adjustment (Line 6 - Line 5)	349
Company Adjustment [1]	0
Net Commission Interest Adjustment (Line 7 - Line 8)	349
State Income Tax Rate	9.99%
State Income Tax Adjustment (Line 9 x Line 10) (Flow to Table II)	35
Net Commission Interest Adjustment (Line 9)	349
State Income Tax Adjustment (Line 11)	35
Net Commission Adjustment for F.I.T. (Line 9 - Line 11)	314
Federal Income Tax Rate	21.00%
Federal Income Tax Adjustment (Line 12 x Line 13) (Flow to Table II)	66

[1] Company Main Brief

Commission Final Allowance
TABLE IV - Wastewater - New Garden
Aqua Pennsylvania Wastewater, Inc. - New Garden
CASH WORKING CAPITAL - Interest and Dividends
R-2021-3027385, R-2021-3027386

Accrued Interest	Long-Term Debt	Short-Term Debt	Preferred Stock Dividends	
Company Rate Base Claim	$30,246,226	$30,246,226	Company Rate Base Claim	$30,246,226
Commission Rate Base Adjustments	($18,970)	($18,970)	Commission Rate Base Adjustme	($18,970)
Commission Rate Base	$30,227,256	$30,227,256	Commission Rate Base	$30,227,256
Weighted Cost of Debt	1.84216100%	0.00%	Weighted Cost Pref. Stock	0.00000000%
Commission Annual Interest Exp.	$556,835	$0	Commission Preferred Dividends	$0
Average Revenue Lag Days	22.9	22.9	Average Revenue Lag Days	22.9
Average Expense Lag Days	91.3	91.3	Average Expense Lag Days	91.3
Net Lag Days	-68.4	-68.4	Net Lag Days	-68.4
Working Capital Adjustment				
Commission Daily Interest Exp.	$1,526	$0	Commission Daily Dividends	$0
Net Lag Days	-68.4	-68.4	Net Lag Days	-68.4
Commission Working Capital	($104,378)	$0		$0
Company Claim [1]	($104,000)	$0	Company Claim [1]	$0
Commission Adjustment	($378)	$0		$0
Total Interest & Dividend Adj.	($378)			

[1] Company Main Brief.

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Commission Final Allowance
TABLE V - Wastewater -New Garden
Aqua Pennsylvania Wastewater, Inc. - New Garden
CASH WORKING CAPITAL -TAXES
R-2021-3027385, R-2021-3027386

Description	Company Proforma Tax Expense Present Rates	Commission Adjustments	Commission Pro forma Tax Expense Present Rates	Commission Allowance	Commission Adjusted Taxes at Present Rates	Daily Expense	Net Lead/ Lag Days	Accrued Tax Adjustment
PA PUC - General Assessments	$19,402	$0	$19,402	$17,047	$36,449	$100	-197.50	($19,722)
	$0	$0	$0		$0	$0	0.00	$0
	$0	$0	$0		$0	$0	0.00	$0
	$0	$0	$0		$0	$0	0.00	$0
	$0	$0	$0		$0	$0	0.00	$0
	$0	$0	$0		$0	$0	0.00	$0
	$0	$0	$0		$0	$0	0.00	$0
	$0	$0	$0		$0	$0	0.00	$0
	$0	$0	$0		$0	$0	0.00	$0
	$0	$0	$0		$0	$0	0.00	$0
	$0	$0	$0		$0	$0	0.00	$0
State Income Tax	($75,351)	$1,651	($73,700)	$248,861	$175,161	$480	45.20	$21,691
Federal Income Tax	($142,571)	$3,124	($139,447)	$470,870	$331,423	$908	33.40	$30,328
	($198,520)	$4,775	($193,745)	$736,778	$543,033	$1,488	21.71	$32,297

[1] Company Main Brief

Average Lag Days in Receipt of Revenues	22.9
Average Lag in Payment of Taxes	21.7
Net Lag	1.2
Average Daily Tax Expense	1,488
Commission Cash Working Capital for Taxes	1,770
Less Company Claim [1]	20,000
Commission Adjustment	(18,230)

Commission Final Allowance
TABLE VI - Wastewater - New Garden
Aqua Pennsylvania Wastewater, Inc. - New Garden
CASH WORKING CAPITAL -- O & M EXPENSE
R-2021-3027385, R-2021-3027386

Description	Company Pro forma F.T.Y. Expense	Commission	Commission Pro forma Expenses	Lag Days	Lag Dollars
Non-Union Labor	$12,085	$0	$12,085	11.00	$132,931
Management Fee [3]	$85,388	$0	$85,388	16.00	$1,366,203
Electric Power	$130,877	($2,794)	$128,083	20.73	$2,654,689
Employee Group Insurance	$7,251	$0	$7,251	16.00	$116,012
Liability Insurance [4]	$2,788	($676)	$2,112	-1.37	($2,894)
SFI Postage	$6,110	$0	$6,110	-7.96	($48,642)
All Other Expenses	$1,563,192	$0	$1,563,192	25.50	$39,861,387
General Inflation [2]	$0	($12,705)	($12,705)	24.40	($310,002)
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$0	$0	$0	0.00	$0
	$1,807,690	($16,175)	$1,791,515	24.40	$43,769,684

Commission Average Revenue Lag	22.9	
Less: Commission Avg. Expense Lag	24.4	
Net Difference	-1.5	Days
Commission Pro forma O & M Expense per Day	$4,908	
Commission CWC for O & M	($7,362)	
Less: Company Claim [1][2]	($7,000)	
Commission Adjustment	($362)	

Notes and Sources to Accompany Table VI – Wastewater – New Garden

(1) Company Main Brief

(2) See Table II - Wastewater - New Garden, Note 2. Reject increases Aqua made to all expense accounts included in its general inflation claim. Since Exhibits 1-A to 1-G at Schedules C-4.1 and G-5.2 use different item descriptions, the number of lag days used for this adjustment is equal to the weighted average O & M Expense lag days for this rate zone after all other adjustments are applied.

(3) See Table II - Wastewater - New Garden, Note 1. SERP expenses are under the management fee account. OCA Exhibit LA-3 at Page 63.

(4) See Table II - Wastewater -New Garden, Note 3.

Blue Chip Financial Forecasts®

Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them

Vol. 42, No. 12, December 1, 2023

Wolters Kluwer

BLUE CHIP FINANCIAL FORECASTS®

Executive Editor: Joseph Aguinaldo
Assistant Editor: Jules Valencia
Haver Analytics
60 East 42nd Street
New York, NY 10165
Phone (212) 986-9300
E-mail: bluechip@haver.com

Robert J. Eggert, Founder
Randell E. Moore, Editor Emeritus
Rocco Impreveduto, General Manager

Blue Chip Financial Forecasts® (ISSN: 0741-8345) is published monthly by CCH Incorporated, 28 Liberty St., 44th Floor New York, NY 10005-1400. Printed in the U.S.A.

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Interest Rates Have Peaked Amid Tight Financial Conditions

The Blue Chip Financial Forecasts (BCFF) see an economy that is likely to slow down in coming quarters due to tighter financial conditions. As a result of slowing growth and an accompanying decline in inflation, market yields are likely to continue to fall. The consensus expects that the Fed has completed its tightening cycle and will begin easing in 2024. The economy is expected to avoid a recession as it has shown resilience (especially in the labor market) in the face of policy tightening.

Slowdown ahead. The latest GDP figures for Q3 2023 showed a sizable 5.2% quarter-to-quarter annualized growth rate, but recent data suggest that demand is dwindling. The Atlanta Fed nowcast is currently pointing to a 2.1% pace in Q4. The BCFF consensus looks for an even slower growth rate of 1.2%. Importantly, the consensus expects tepid growth to persist for the entire forecast horizon. The average GDP growth forecast for all of 2024 is 0.7%, with particular weakness in the first three quarters.

In a special question, the median BCFF forecaster puts the odds of recession in the next 12 months at 45%. A significant minority of forecasters (27%) believes that a recession is the most likely path for the economy, and expects two or more consecutive quarterly declines in GDP. The other 73% of panelists expect a slowdown without recession.

Consistent with a soft economic outlook, the consensus projects continued declines in the inflation rate. The PCE inflation rate is expected to slide to 2.2% by midyear 2024, nearly a percentage point lower than the current inflation rate.

Tight financial conditions. Earlier this year, market interest rates had increased to levels not seen since before the 2008 financial crisis. For example, the 10-year Treasury yield nearly reached 5% in October. Rates rose for a variety of reasons including data showing economic resilience, which in turn signaled that the Fed might have to keep rates high for longer than anticipated. High rates have taken a toll on interest-sensitive sectors, such as housing and capital goods expenditures. There is a growing sense that elevated rates have done some of the work for the Fed in slowing the economy. In a special question, BCFF panelists overwhelmingly stated that the rise in rates has tightened financial conditions sufficiently to delay/prevent further interest rate increases.

Indeed, with the funds rate above 5%, inflation subsiding, and Fed asset holdings declining, policy does already seem quite tight. In a special question, panelists estimated that the neutral fed funds rate was 2.9%, which is well below the current funds rate target.

Falling market yields. As a result of tightening financial conditions and the drag on economic activity, the 10-year yield has actually begun to decline, falling by more than 60 basis points in the past month. This decline was aided by better-than-expected inflation news for October, with the CPI posting an unchanged reading for a 3.2% rise year to year. Core CPI rose 0.2% for a 4.0% rise year to year, the lowest reading since August 2021.

The BCFF consensus expectation that both economic growth and inflation will slow significantly in the near term is being reflected in projections for market rates. The slide in rates over the past month is expected to continue over the next six quarters. For example, consensus expectations for the 10-year Treasury yield are for a half-point drop to 4.3% by Q1 2025. At the same time, the 1-year Treasury bill rate is expected to fall by nearly 1.5 percentage points to 4.1%, suggesting a significant steepening of the yield curve and a move away from inversion.

Importantly, the BCFF consensus expects mortgage rates to fall by nearly 1 percentage point over the next six quarters, which could bring much needed relief to the beleaguered housing market. The weakness in the economy is also expected to affect corporate debt somewhat, as panelists look for the spread between corporates and Treasurys to widen slightly.

No more Fed tightening. Policymakers have made a point of leaving the door open to further hikes, even as Fed Chair Powell suggests that the economy may be resistant to higher rates. While supply chains have improved, aiding the decline in inflation, Powell has stated repeatedly that the path to lower inflation involves below-trend growth and softening in the labor market. Conversely, BCFF panelists believe that the Fed is finished hiking rates. In a special question, 100 percent of panelists indicated that the Fed had completed its tightening cycle. Markets agree – the federal funds futures market does not price in any further tightening either.

Funds rate cuts. Against this backdrop, every BCFF panelist expects the Fed to cut the fed funds rate in the forecast horizon. Three-quarters of the panelists believe the Fed will cut rates for the first time either in Q2 or Q3 2024. Respondents seem to be pushing out the timing of the first rate cut – two months ago no panelist thought rate cuts would start after Q3 2024, now 22% do. Still, the BCFF consensus is that the fed funds rate will drop to 4.2% by Q1 2025, with nearly all panelists indicating that Fed easing will be ongoing at that time.

Long-range forecasts. The Blue Chip semi-annual longer-range forecasts show BCFF panelists' views on trend growth, inflation, and interest rates out to 2034. From 2026 on, panelists expect US GDP growth will hover near 2%, which is slightly higher than the CBO estimate of the steady state. They anticipate inflation will subside toward the Fed's target through 2026 and remain there.

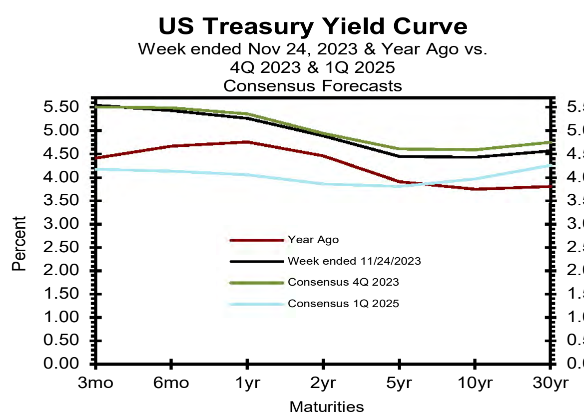
Interest rates are expected to fall but remain elevated relative to pre-pandemic norms. The BCFF consensus looks for the funds rate to drop to 3% by 2028 and remain there. Similarly, the 10-year yield is expected to decline to 3.9% in 2025 and stay there. For comparison, in the decade prior to the latest tightening cycle, the funds rate averaged 0.6% and the 10-year yield averaged 2%. The higher rate projections are consistent with panelists' judgments about the neutral fed funds rate, which is substantially higher than before the pandemic.

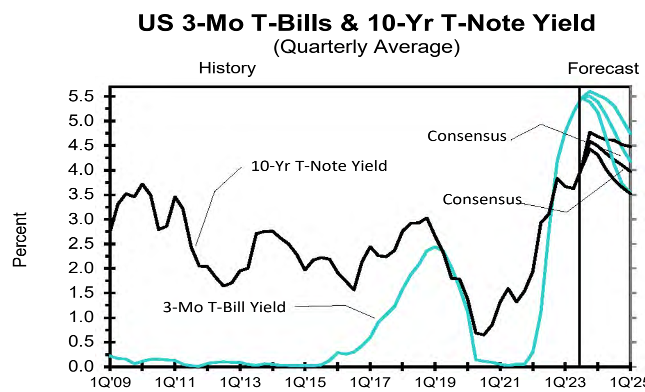
Peter D'Antonio (Haver Analytics, New York, NY)

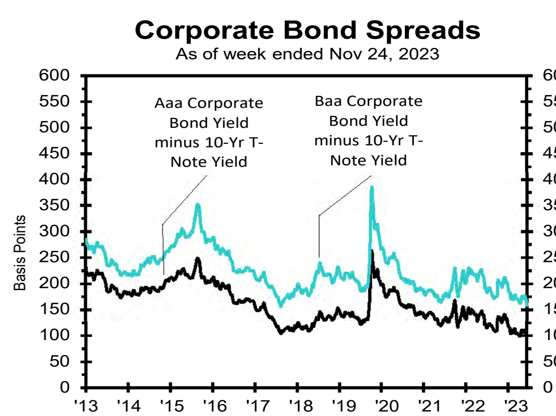
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

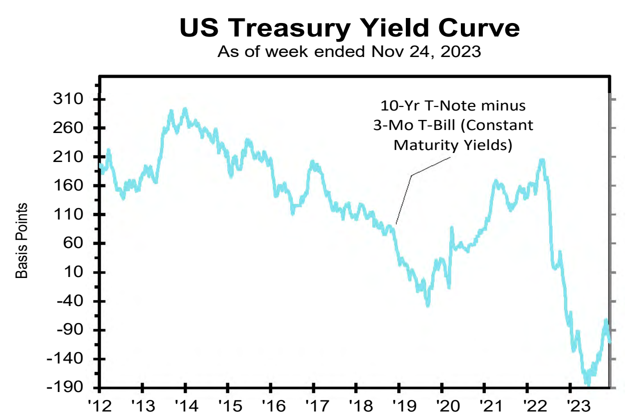
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	4Q	1Q	2Q	3Q	4Q	1Q
Interest Rates	Nov 24	Nov 17	Nov 10	Nov 3	Oct	Sep	Aug	3Q 2023	**2023**	**2024**	**2024**	**2024**	**2024**	**2025**
Federal Funds Rate	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.26	**5.4**	**5.4**	**5.2**	**4.9**	**4.6**	**4.2**
Prime Rate	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.43	**8.5**	**8.5**	**8.3**	**8.1**	**7.7**	**7.4**
SOFR	5.31	5.32	5.32	5.33	5.31	5.31	5.30	5.23	**5.4**	**5.3**	**5.2**	**4.9**	**4.6**	**4.3**
Commercial Paper, 1-mo.	5.33	5.34	5.32	5.33	5.33	5.31	5.30	5.26	**5.4**	**5.4**	**5.1**	**4.9**	**4.5**	**4.2**
Treasury bill, 3-mo.	5.54	5.52	5.54	5.57	5.60	5.56	5.56	5.54	**5.5**	**5.4**	**5.1**	**4.8**	**4.5**	**4.2**
Treasury bill, 6-mo.	5.43	5.41	5.46	5.51	5.57	5.51	5.54	5.53	**5.5**	**5.3**	**5.1**	**4.7**	**4.4**	**4.1**
Treasury bill, 1 yr.	5.26	5.27	5.35	5.38	5.42	5.44	5.37	5.39	**5.4**	**5.2**	**4.9**	**4.6**	**4.3**	**4.1**
Treasury note, 2 yr.	4.89	4.89	4.97	4.97	5.07	5.02	4.90	4.92	**4.9**	**4.8**	**4.5**	**4.2**	**4.0**	**3.9**
Treasury note, 5 yr.	4.45	4.50	4.59	4.69	4.77	4.49	4.31	4.31	**4.6**	**4.5**	**4.3**	**4.1**	**4.0**	**3.8**
Treasury note, 10 yr.	4.43	4.50	4.59	4.75	4.80	4.38	4.17	4.15	**4.6**	**4.5**	**4.3**	**4.2**	**4.1**	**4.0**
Treasury note, 30 yr.	4.57	4.65	4.75	4.93	4.95	4.47	4.28	4.24	**4.8**	**4.7**	**4.5**	**4.5**	**4.4**	**4.3**
Corporate Aaa bond	5.41	5.53	5.66	5.86	5.87	5.38	5.25	5.20	**5.5**	**5.5**	**5.3**	**5.3**	**5.1**	**5.0**
Corporate Baa bond	6.02	6.17	6.31	6.52	6.53	6.03	5.90	5.86	**6.4**	**6.4**	**6.4**	**6.3**	**6.2**	**6.1**
State & Local bonds	4.45	4.55	4.67	4.90	4.88	4.54	4.39	4.38	**4.6**	**4.7**	**4.6**	**4.6**	**4.5**	**4.4**
Home mortgage rate	7.29	7.44	7.50	7.76	7.62	7.20	7.07	7.04	**7.4**	**7.3**	**7.1**	**6.9**	**6.7**	**6.5**
	History								Consensus Forecasts-Quarterly					
	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	**4Q**	**1Q**	**2Q**	**3Q**	**4Q**	**1Q**
Key Assumptions	2021	2022	2022	2022	2022	2023	2023	2023	**2023**	**2024**	**2024**	**2024**	**2024**	**2025**
Fed's AFE $ Index	106.9	108.3	113.5	118.8	119.8	115.5	114.6	115.1	**116.6**	**116.3**	**115.9**	**115.9**	**115.7**	**115.7**
Real GDP	7.0	-2.0	-0.6	2.7	2.6	2.2	2.1	5.2	**1.2**	**0.7**	**0.3**	**0.6**	**1.2**	**1.7**
GDP Price Index	7.0	8.5	9.1	4.4	3.9	3.9	1.7	3.6	**2.7**	**2.4**	**2.3**	**2.2**	**2.2**	**2.2**
Consumer Price Index	8.8	9.2	9.7	5.5	4.2	3.8	2.7	3.6	**2.9**	**2.5**	**2.3**	**2.5**	**2.3**	**2.2**
PCE Price Index	6.8	7.7	7.2	4.7	4.1	4.2	2.5	2.8	**2.6**	**2.4**	**2.2**	**2.3**	**2.2**	**2.1**

Forecasts for interest rates and the Federal Reserve's Advanced Foreign Economies Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, CPI and PCE Price Index are seasonally adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP, GDP Price Index and PCE Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index history is from the Department of Labor's Bureau of Labor Statistics (BLS).









Policy Rates[1]

	History: Latest	History: Month Ago	History: Year Ago	Consensus Forecasts Months From Now: 3	6	12
U.S.	5.38	5.38	3.88	**5.28**	**5.06**	**4.52**
Japan	-0.10	-0.10	-0.10	**-0.08**	**-0.06**	**0.01**
U.K.	5.25	5.25	3.00	**5.25**	**5.01**	**4.25**
Switzerland	1.75	1.75	0.50	**1.78**	**1.72**	**1.55**
Canada	5.00	5.00	3.75	**5.03**	**4.78**	**4.12**
Australia	4.35	4.10	2.85	**4.32**	**4.24**	**3.81**
Euro area	4.50	4.50	2.00	**4.39**	**4.11**	**3.61**

10-Yr. Government Bond Yields[2]

	History: Latest	History: Month Ago	History: Year Ago	Consensus Forecasts Months From Now: 3	6	12
U.S.	4.47	4.84	3.68	**4.54**	**4.33**	**4.03**
Germany	2.64	2.81	1.97	**2.60**	**2.50**	**2.32**
Japan	0.79	0.88	0.28	**0.88**	**0.86**	**0.90**
U.K.	4.34	4.61	3.26	**4.25**	**4.12**	**3.87**
France	3.20	3.45	2.44	**3.17**	**3.03**	**2.87**
Italy	4.39	4.84	3.85	**4.43**	**4.28**	**4.15**
Switzerland	0.98	1.09	1.01	**1.10**	**1.17**	**1.19**
Canada	3.72	3.98	2.94	**3.78**	**3.52**	**3.37**
Australia	4.55	4.81	3.58	**4.70**	**4.33**	**3.95**
Spain	3.58	3.98	2.82	**3.67**	**3.51**	**3.40**

Foreign Exchange Rates[3]

	History: Latest	History: Month Ago	History: Year Ago	Consensus Forecasts Months From Now: 3	6	12
U.S.	115.81	118.73	117.55	**115.9**	**114.9**	**113.6**
Japan	149.57	149.60	139.21	**148.1**	**145.4**	**139.8**
U.K.	1.26	1.22	1.21	**1.24**	**1.24**	**1.26**
Switzerland	0.88	0.90	0.95	**0.90**	**0.89**	**0.88**
Canada	1.36	1.39	1.34	**1.36**	**1.34**	**1.31**
Australia	0.66	0.64	0.68	**0.65**	**0.66**	**0.69**
Euro	1.09	1.06	1.04	**1.08**	**1.09**	**1.11**

Consensus Policy Rates vs. US Rate

	Now	In 12 Mo.
Japan	-5.48	**-4.51**
U.K.	-0.13	**-0.28**
Switzerland	-3.63	**-2.98**
Canada	-0.38	**-0.40**
Australia	-1.03	**-0.72**
Euro area	-0.88	**-0.92**

Consensus 10-Year Gov't Yields vs. U.S. Yield

	Now	In 12 Mo.
Germany	-1.83	**-1.71**
Japan	-3.68	**-3.13**
U.K.	-0.13	**-0.16**
France	-1.27	**-1.17**
Italy	-0.08	**0.12**
Switzerland	-3.49	**-2.85**
Canada	-0.75	**-0.66**
Australia	0.08	**-0.08**
Spain	-0.89	**-0.63**

Forecasts of panel members are on pages 10 and 11. Definitions of variables are as follows: [1]Monetary policy rates. [2]Government bonds are yields to maturity. [3]Foreign exchange rate forecasts for U.K., Australia and the Euro are U.S. dollars per currency unit. For the U.S dollar, forecasts are of the U.S. Federal Reserve Board's AFE Dollar Index.

International. Growing conviction that central banks have concluded their tightening cycles has fueled a rally in both bond and equity markets over the past few weeks. That conviction has been bolstered by a number of factors. First, global inflationary pressures have continued to diminish, in large part because of weaker energy prices. And, notwithstanding the recent instability in the Middle East, oil prices have continued to decline over the past two months, which has further eased concerns that this trend toward weaker inflation might stall. Second, there is growing evidence to suggest that higher interest rates are taking a heavier toll on global economic activity, evidence that's particularly compelling in the euro area and the UK. Lastly, the latest policy decisions and accompanying statements from various central banks - including the Fed, the ECB, and the BoE - indicate a growing consensus among policymakers that further tightening may not be necessary.

This month's survey of Blue Chip Financial Forecasters aligns with that narrative. The policy rate projections for the US, Canada, Europe, and Australia, for example, indicate a broadly shared consensus that tightening cycles have reached their conclusion. And that corresponds too with the responses to a special question, where approximately 90% of panelists believe the ECB and BoE have completed their tightening cycles with that proportion rising to 100% for the Fed.

Closer scrutiny of these policy rate projections further reveals that easing cycles are now expected to commence in the euro area, Switzerland, Australia, the UK as well as the US within the next 6 months. Financial futures contracts, moreover, indicate that investors believe that easing campaigns could potentially begin even earlier. Those views do not, however, chime with the messages from central banks in recent weeks. Even the more dovish members of most central banks' policy committees have staunchly opposed these views over the last few weeks.

That dichotomy of views could reflect a more downbeat view from our panelists about the outlook for growth and inflation next year compared with the expectations of central banks. In response to another special question, for example, 55% of our panelists expect a euro area recession over the next 12 months while 58% expect a UK recession. As noted above, moreover, downbeat views about the growth outlook – and euro area growth in particular - have been validated of late by much of the incoming data. The flash PMI surveys for November, for example, reveal ongoing contractions in the manufacturing sector in the euro area, UK, Japan and the US.

Still, those recession odds for Europe and downbeat data points for manufacturing have not been amplified elsewhere. For example, only 44% of our panelists now anticipate a US recession phase over the next 12 months, down a little from 47% in our last survey. Those same flash PMI surveys for November, in the meantime, suggest that activity has held up quite well in the service sector in the US, UK and Japan.

Against this backdrop, investors are likely to be alert to how this dichotomy of views is resolved. Will the incoming data for both growth and inflation disappoint to the downside and thereby validate the consensus view that easing cycles will shortly commence? Alternatively, will growth and hold up and thereby challenge the dovish Blue Chip consensus but at the same time validate the more hawkish central bank consensus?

However, the outlook for the world economy and financial markets will not solely hinge on these considerations. Economic developments in Asia will also be closely watched. In response to another special question, 74% of our panelists believe the situation in China poses significant risks to global growth. Moreover, Japan's economic outlook could wield considerable influence over global financial stability as well. There is ample speculation in particular about if and when the BoJ will start to normalize its monetary policy. In a final special question this month, for example, 62% of our panelists expect that an interest rate normalization campaign could begin before the middle of 2024.

Fourth Quarter 2023

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term			Long-Term					Avg. For ---Qtr.---	(Q-Q % Change) (SAAR)			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	A.	B.	C.	D.	E.
	Federal Funds Rate	Prime Bank Rate	SOFR Rate	Com. Paper 1-Mo.	Treas. Bills 3-Mo.	Treas. Bills 6-Mo.	Treas. Bills 1-Yr.	Treas. Notes 2-Yr.	Treas. Notes 5-Yr.	Treas. Notes 10-Yr.	Treas. Bond 30-Yr.	Aaa Corp. Bond	Baa Corp. Bond	State & Local Bonds	Home Mtg. Rate	Fed's Adv Fgn Econ $ Index	Real GDP	GDP Price Index	Cons. Price Index	PCE Price Index
Scotiabank Group	5.5 H	na	5.3 L	na	5.5	na	na	5.2 H	5.0 H	5.0 H	5.1 H	na	na	na	na	na	0.2 L	1.5 L	4.7 H	4.7 H
TS Lombard	5.5 H	8.6 H	5.4	5.5	5.4	5.5	5.1 L	4.7 L	4.3	4.4	4.5	5.2	6.1	4.4	6.2 L	115.0	1.5	3.6 H	3.6	3.6
Bank of America	5.4	na	na	na	na	na	na	4.9	4.7	4.5	4.8	na	na	na	na	na	1.5	2.7	2.6	2.5
BMO Capital Markets	5.4	8.5	5.3 L	5.4	5.6 H	5.5	5.3	4.9	4.6	4.6	4.7	5.5	6.6	5.1	7.5	117.8	0.9	2.2	2.8	2.3
Chan Economics	5.4	8.4 L	5.3 L	5.3 L	5.4	5.5	5.3	4.8	4.3	4.4	4.6	5.6	6.6	5.0	7.2	115.0	1.5	2.7	2.9	2.6
Comerica Bank	5.4	8.6 H	5.4	na	5.4	5.5	5.3	4.9	4.7	4.7	4.9	5.6	6.6	na	7.7	na	0.7	2.4	2.4	2.4
Daiwa Capital Markets America	5.4	8.5	na	na	5.3 L	na	na	4.9	4.5	4.5	4.7	na	na	na	7.3	117.0	1.0	2.6	3.0	3.3
Fannie Mae	5.4	8.5	na	na	5.5	5.5	5.3	4.9	4.5	4.5	4.7	na	na	na	7.3	na	1.1	2.9	2.4	2.4
Georgia State University	5.4	8.5	na	na	5.5	5.4	5.5	5.0	4.7	4.6	4.8	5.5	6.6	na	7.6	na	1.1	2.6	2.8	2.6
GLC Financial Economics	5.4	8.5	5.4	5.4	5.5	5.4	5.3	4.8	4.5	4.4	4.6	5.2	6.0 L	4.2	6.8	117.1	0.7	3.6 H	2.4	2.0
Goldman Sachs & Co.	5.4	na	na	na	5.6 H	na	na	5.0	4.7	4.8	4.4	na	na	na	na	na	1.9	1.8	2.6	2.1
ING	5.4	na	na	na	na	na	na	4.8	4.5	4.5	4.6	na	na	na	na	na	1.9	na	na	na
J.P. Morgan Chase	5.4	na	na	na	na	na	na	4.7 L	4.2 L	4.1 L	4.3 L	na	na	na	na	na	2.0 H	3.0	2.9	2.4
KPMG	5.4	8.5	5.4	5.4	5.6 H	5.6	5.5	5.1	4.7	4.7	4.8	5.6	6.7	na	7.6	na	1.1	2.9	2.8	2.6
MacroPolicy Perspectives	5.4	8.5	5.3 L	5.4	5.6 H	5.5	5.4	5.0	4.7	4.5	4.8	5.1 L	6.0 L	4.5	7.3	116.1	1.5	2.5	3.1	2.1
Nomura Securities, Inc.	5.4	8.5	na	na	na	na	na	4.9	4.6	4.6	na	na	na	na	na	na	0.9	1.9	2.8	2.4
Oxford Economics	5.4	8.5	5.4	na	5.6 H	5.6	5.4	5.1	4.7	4.7	4.9	5.3	na	na	7.6	118.8 H	1.0	2.7	4.3	3.3
RDQ Economics	5.4	8.5	5.4	5.8 H	5.5	5.5	5.2	4.9	4.7	4.6	4.7	5.5	6.3	4.7	7.4	116.9	1.5	3.2	3.0	2.8
S&P Global Market Intelligence	5.4	8.5	5.4	na	5.5	5.4	5.5	5.1	4.7	4.7	4.9	na	na	na	7.6	na	1.1	2.9	2.8	2.6
The Lonski Group	5.4	8.5	5.3 L	5.4	5.5	5.5	5.2	4.9	4.6	4.6	4.7	5.6	6.3	4.6	7.4	117.0	1.1	2.6	2.9	3.5
The Northern Trust Company	5.4	8.5	5.3 L	5.4	5.6 H	5.5	5.4	5.0	4.6	4.6	4.8	5.4	6.4	4.7	7.5	117.5	0.8	2.3	3.2	2.9
Wells Fargo	5.4	8.5	5.4	5.4	5.4	5.4	5.2	4.8	4.5	4.5	4.7	5.7	6.7	5.1	7.5	na	0.7	2.7	3.4	2.7
Action Economics	5.3 L	8.5	5.7 H	5.4	5.5	5.5	5.4	5.0	4.8	4.9	5.0	5.7	6.7	4.5	8.0 H	115.1	1.6	2.2	2.2	1.4 L
Barclays	5.3 L	na	na	na	5.4	na	na	na	na	na	na	na	na	na	na	na	1.5	2.8	2.9	2.7
Chmura Economics & Analytics	5.3 L	8.5	5.3 L	5.4	5.6 H	5.5	5.4	5.0	4.6	4.6	4.8	5.4	na	na	7.5	na	1.7	3.3	3.3	3.1
DePrince & Assoc.	5.3 L	8.5	5.4	5.4	5.6 H	5.5	5.4	5.0	4.6	4.6	4.8	5.4	6.4	4.3	7.5	116.7	1.1	3.0	3.3	3.1
Economist Intelligence Unit	5.3 L	8.5	na	5.4	5.6 H	5.5	5.3	5.1	4.7	4.5	4.8	na	na	na	7.5	na	0.6	na	2.9	na
EY-Parthenon	5.3 L	na	na	na	5.4	na	na	na	na	4.6	na	na	na	na	na	na	1.3	2.7	2.5	2.1
Loomis, Sayles & Company	5.3 L	8.5	5.3 L	5.3 L	5.5	5.5	5.3	5.0	4.6	4.5	4.7	5.3	6.3	4.6	7.4	117.2	1.1	2.9	2.9	2.6
MacroFin Analytics & Rutgers Bus School	5.3 L	8.5	5.3 L	5.4	5.5	5.4	5.4	4.9	4.4	4.5	4.6	5.5	6.0 L	4.5	7.4	115.8	1.2	3.3	3.3	2.7
Moody's Analytics	5.3 L	8.5	5.3 L	5.4	5.3 L	5.3 L	5.3	5.1	4.8	4.7	5.0	5.8	6.8 H	4.4	7.7	na	0.8	2.7	3.2	3.1
NatWest Markets	5.3 L	na	na	5.4	5.6 H	5.7 H	5.8 H	4.8	4.5	4.5	4.8	5.8	6.7	5.2 H	7.0	na	1.0	2.2	2.5	2.2
PNC Financial Services Corp.	5.3 L	8.5	5.3 L	na	5.4	5.5	5.4	5.0	4.7	4.6	4.8	na	6.5	4.1	7.5	114.6 L	1.4	2.7	2.4	2.1
Regions Financial Corporation	5.3 L	8.5	5.3 L	5.4	5.5	5.5	5.3	4.9	4.6	4.6	4.7	5.6	6.4	4.7	7.4	117.3	0.6	2.7	2.9	2.7
Santander Capital Markets	5.3 L	8.5	5.3 L	5.4	5.6 H	5.5	5.3	4.9	4.6	4.6	4.8	5.4	6.4	3.9 L	7.5	116.8	1.9	3.0	2.6	2.5
Societe Generale	5.3 L	8.5	5.3 L	na	5.5	5.5	5.3	4.9	4.6	4.6	4.7	na	na	na	na	na	1.6	2.7	2.7	2.0
Via Nova Investment Mgt.	5.3 L	8.5	5.3 L	5.3 L	5.6 H	5.5	5.5	5.1	4.8	4.9	5.0	6.0 H	6.6	4.9	7.7	117.6	2.0 H	2.2	2.1 L	2.0
December Consensus	**5.4**	**8.5**	**5.4**	**5.4**	**5.5**	**5.5**	**5.4**	**4.9**	**4.6**	**4.6**	**4.8**	**5.5**	**6.4**	**4.6**	**7.4**	**116.6**	**1.2**	**2.7**	**2.9**	**2.6**
Top 10 Avg.	5.4	8.5	5.4	5.5	5.6	5.5	5.5	5.1	4.8	4.8	4.9	5.7	6.7	4.9	7.7	117.4	1.8	3.2	3.5	3.3
Bottom 10 Avg.	5.3	8.5	5.3	5.4	5.4	5.4	5.3	4.8	4.4	4.4	4.6	5.3	6.2	4.3	7.1	115.9	0.7	2.1	2.4	2.0
November Consensus	5.4	8.5	5.4	5.4	5.5	5.5	5.4	5.0	4.7	4.7	4.8	5.6	6.6	4.8	7.5	117.6	0.9	2.7	3.2	2.9
Number of Forecasts Changed From A Month Ago:																				
Down	8	4	4	4	13	16	12	18	20	20	17	13	12	14	17	11	9	15	21	19
Same	29	24	21	16	16	8	13	12	8	6	7	3	4	5	2	4	9	5	5	8
Up	0	1	0	1	4	4	3	5	7	10	10	7	6	0	9	3	19	15	10	8
Diffusion Index	39%	45%	42%	43%	36%	29%	34%	31%	31%	36%	40%	37%	36%	13%	36%	28%	64%	50%	35%	34%

First Quarter 2024

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	1 Federal Funds Rate	2 Prime Bank Rate	3 SOFR Rate	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Adv Fgn Econ $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index	E. PCE Price Index
	---Percent Per Annum -- Average For Quarter---															Avg. For ---Qtr.---	---(Q-Q % Change)--- ---(SAAR)---			
	---Short-Term---							---Intermediate-Term---			---Long-Term---									
S&P Global Market Intelligence	5.6 H	8.7 H	5.6	na	5.6 H	5.5	5.6	5.1 H	4.7	4.6	4.8	na	na	na	7.5	na	0.9	2.4	1.9	1.9
J.P. Morgan Chase	5.5	na	na	na	na	na	na	4.8	4.4	4.4	4.6	na	na	na	na	na	1.3	1.9	2.1	1.7
Scotiabank Group	5.5	na	5.3	na	5.4	na	na	4.4	4.2	4.5	4.6	na	na	na	na	na	0.0	1.6 L	2.3	2.6
Bank of America	5.4	na	na	na	na	na	na	4.8	4.5	4.4	4.7	na	na	na	na	na	0.5	3.1	3.2	3.1
BMO Capital Markets	5.4	8.5	5.3	5.4	5.5	5.4	5.1	4.6	4.4	4.4	4.6	5.4	6.5	5.0	7.4	117.2	0.2	2.7	3.2	3.0
Chan Economics	5.4	8.4	5.3	5.3	5.4	5.5	5.3	4.8	4.3	4.4	4.6	5.6	6.6	5.0	7.2	114.7	1.0	2.6	2.8	2.4
Chmura Economics & Analytics	5.4	8.5	5.4	5.4	5.5	5.5	5.4	4.9	4.6	4.6	4.7	5.4	na	na	7.6	na	0.3	3.0	3.0	2.9
Comerica Bank	5.4	8.6	5.4	na	5.4	5.4	5.1	4.5	4.4	4.5	4.7	5.4	6.3	na	7.3	na	0.5	2.2	2.4	2.5
Daiwa Capital Markets America	5.4	8.5	na	na	5.3	na	na	4.5	4.1 L	4.3	4.4 L	na	na	na	7.1	116.0	-1.0 L	2.6	2.6	2.5
DePrince & Assoc.	5.4	8.5	5.4	5.4	5.5	5.4	5.3	4.9	4.6	4.6	4.7	5.5	6.5	4.6	7.3	117.2	0.7	2.7	2.9	2.7
GLC Financial Economics	5.4	8.5	5.4	5.3	5.4	5.2	5.0	4.5	4.7	4.6	4.7	5.4	6.2	4.4	6.7	116.9	1.3	3.5 H	2.8	2.4
Goldman Sachs & Co.	5.4	na	na	na	5.5	na	na	5.0	4.7	4.8 H	4.7	na	na	na	na	na	1.8	2.3	2.7	2.4
ING	5.4	na	na	na	na	na	na	4.5	4.2	4.3	4.5	na	na	na	na	na	0.0	na	na	na
KPMG	5.4	8.5	5.4	5.3	5.5	5.6	5.5	5.0	4.7	4.6	4.7	5.5	6.6	na	7.5	na	0.8	2.4	1.9	1.9
MacroPolicy Perspectives	5.4	8.5	5.3	na	na	na	na	4.7	4.3	4.5	na	na	na	na	7.2	na	1.2	2.0	1.8	1.6
Nomura Securities, Inc.	5.4	8.5	na	na	na	na	na	4.8	4.5	4.5	na	na	na	na	na	na	1.3	1.6 L	2.5	2.2
Oxford Economics	5.4	8.5	5.4	na	5.6 H	5.5	5.4	5.0	4.6	4.6	4.8	5.3	na	na	7.5	119.4 H	0.0	2.6	2.9	2.5
RDQ Economics	5.4	8.5	5.4	6.0 H	5.3	5.2	4.9	4.7	4.6	4.6	4.6	5.8	6.6	4.7	7.3	117.3	0.5	3.0	3.4 H	3.2 H
The Northern Trust Company	5.4	8.5	5.3	5.4	5.5	5.4	5.4	5.0	4.8	4.7	5.0 H	5.6	6.6	4.9	7.6	116.0	0.9	2.3	2.8	2.6
Wells Fargo	5.4	8.5	5.4	5.4	5.2	5.1	4.7	4.4	4.2	4.3	4.6	5.5	6.5	4.9	7.2	na	0.9	2.5	2.9	2.5
Action Economics	5.3	8.5	5.8 H	5.4	5.5	5.4	5.3	4.9	4.7	4.7	4.8	5.6	6.6	4.5	7.8 H	118.4	0.6	1.8	1.9	1.4 L
Barclays	5.3	na	na	na	5.4	na	na	5.0	4.7	4.8 H	5.0 H	na	na	na	na	na	1.0	3.1	2.9	3.0
Economist Intelligence Unit	5.3	8.5	na	5.4	5.5	5.4	5.1	5.0	4.7	4.6	4.8	na	na	na	7.5	na	-0.9	na	2.3	na
EY-Parthenon	5.3	na	na	na	5.0	na	na	na	na	4.2 L	na	na	na	na	na	na	-0.1	2.5	2.5	2.2
Fannie Mae	5.3	8.4	na	na	5.3	5.3	5.0	4.7	4.3	4.4	4.5	na	na	na	7.0	na	0.1	2.2	1.8	1.8
Georgia State University	5.3	8.4	na	na	5.4	5.2	5.2	4.8	4.5	4.5	4.7	5.4	6.6	na	7.4	na	0.3	2.3	1.9	1.9
Loomis, Sayles & Company	5.3	8.5	5.3	5.3	5.5	5.5	5.3	5.0	4.6	4.5	4.7	5.3	6.3	4.6	7.3	116.8	1.5	2.1	1.7 L	1.6
MacroFin Analytics & Rutgers Bus School	5.3	8.5	5.3	5.4	5.3	5.4	5.4	4.8	4.4	4.4	4.5	5.4	5.9 L	4.4	7.2	115.7	1.0	2.5	2.8	2.6
Moody's Analytics	5.3	8.5	5.3	5.3	5.1	5.1	5.0	4.8	4.5	4.3	4.7	5.7	6.7	4.4	7.1	na	1.1	2.1	2.7	2.4
NatWest Markets	5.3	na	na	5.4	5.6 H	5.7 H	5.8 H	4.5	4.3	4.4	4.7	5.7	6.6	5.1	6.9	na	1.3	1.6 L	2.2	1.9
PNC Financial Services Corp.	5.3	8.5	5.3	na	5.3	5.4	5.2	4.9	4.7	4.5	4.6	na	6.9 H	5.3 H	7.4	115.0	0.4	2.2	1.8	1.8
Regions Financial Corporation	5.3	8.5	5.3	5.4	5.5	5.4	5.2	4.8	4.4	4.4	4.6	5.3	6.3	4.6	7.2	116.5	0.4	2.4	2.8	2.9
Santander Capital Markets	5.3	8.5	5.3	5.4	5.5	5.4	5.2	4.9	4.5	4.6	4.8	5.4	6.4	4.0 L	7.4	116.0	1.2	3.1	2.8	2.6
Societe Generale	5.3	8.5	5.3	na	5.3	5.1	4.7	4.2 L	4.3	4.3	4.5	na	na	na	na	na	0.5	1.8	2.2	2.2
The Lonski Group	5.3	8.5	5.3	5.4	5.5	5.3	5.0	4.8	4.5	4.3	4.5	5.4	6.1	4.5	7.2	117.9	0.4	2.2	2.3	2.6
Via Nova Investment Mgt.	5.3	8.5	5.4	5.4	5.3	5.3	5.3	4.9	4.9 H	4.8 H	4.9	5.9 H	6.5	4.8	7.6	116.0	2.5 H	2.1	2.1	2.1
TS Lombard	4.8 L	7.9 L	4.8 L	4.8 L	4.7 L	4.8 L	4.5 L	4.3	4.2	4.3	4.4 L	5.1 L	6.0	4.3	6.1 L	110.0 L	0.2	3.2	3.2	3.2 H
December Consensus	**5.4**	**8.5**	**5.3**	**5.4**	**5.4**	**5.3**	**5.2**	**4.8**	**4.5**	**4.5**	**4.7**	**5.5**	**6.4**	**4.7**	**7.3**	**116.3**	**0.7**	**2.4**	**2.5**	**2.4**
Top 10 Avg.	5.4	8.5	5.5	5.5	5.5	5.5	5.4	5.0	4.7	4.7	4.8	5.6	6.6	4.9	7.5	117.4	1.5	3.0	3.0	2.9
Bottom 10 Avg.	5.3	8.4	5.3	5.3	5.2	5.2	4.9	4.4	4.2	4.3	4.5	5.3	6.3	4.4	7.0	115.3	-0.1	1.9	1.9	1.8
November Consensus	5.4	8.5	5.4	5.4	5.4	5.4	5.2	4.8	4.5	4.5	4.7	5.5	6.5	4.8	7.3	118.0	0.3	2.4	2.5	2.4
Number of Forecasts Changed From A Month Ago:																				
Down	10	7	7	6	12	10	10	14	12	14	12	12	11	13	13	11	10	14	11	12
Same	25	19	17	9	13	11	13	15	13	10	11	3	3	2	6	3	12	9	8	11
Up	2	3	1	5	7	6	4	7	11	13	11	7	7	3	9	3	15	12	17	12
Diffusion Index	39%	43%	38%	48%	42%	43%	39%	40%	49%	49%	49%	39%	40%	22%	43%	26%	57%	47%	58%	50%

Second Quarter 2024

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term			Long-Term					Avg. For ---Qtr.---	(Q-Q % Change) (SAAR)			
	1 Federal Funds Rate	2 Prime Bank Rate	3 SOFR Rate	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Adv Fgn Econ $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index	E. PCE Price Index
S&P Global Market Intelligence	5.6 H	8.7 H	5.5	na	5.4	5.2	5.2	4.8	4.4	4.4	4.6	na	na	na	7.2	na	0.1	2.9	2.8	2.6
J.P. Morgan Chase	5.5	na	na	na	na	na	na	4.6	4.3	4.4	4.7	na	na	na	na	na	0.5	2.0	1.9	1.5
Action Economics	5.4	8.5	5.8 H	5.4	5.5	5.3	5.1	4.8	4.6	4.6	4.7	5.4	6.4	4.4	7.7 H	118.7	1.0	1.9	2.3	1.7
BMO Capital Markets	5.4	8.5	5.3	5.4	5.5	5.4	5.0	4.3	4.3	4.3	4.5	5.4	6.5	5.0	7.3	117.2	0.8	2.2	2.4	2.3
Chan Economics	5.4	8.4	5.3	5.3	5.4	5.5 H	5.3 H	4.8	4.3	4.4	4.6	5.6	6.6	5.0	7.2	114.8	0.5	2.6	2.8	2.4
Goldman Sachs & Co.	5.4	na	na	na	5.3	na	na	4.9	4.6	4.7	4.7	na	na	na	na	na	1.6	2.2	2.3	2.3
Nomura Securities, Inc.	5.4	8.5	na	na	na	na	na	4.6	4.4	4.5	na	na	na	na	na	na	1.4	1.5	2.2	1.9
Oxford Economics	5.4	8.5	5.4	na	5.6 H	5.5 H	5.3 H	5.0 H	4.4	4.4	4.7	5.2	na	na	7.3	119.0 H	0.0	2.2	2.3	2.2
RDQ Economics	5.4	8.5	5.4	5.9 H	5.3	5.2	4.8	4.5	4.5	4.5	4.5	5.9 H	7.0	4.7	7.1	116.4	-1.1	3.1	3.4 H	3.2 H
The Northern Trust Company	5.4	8.5	5.3	5.5	5.4	5.4	5.3 H	4.7	4.7 H	4.7	5.0 H	5.7	6.8	5.0	7.5	115.0	1.1	2.2	2.5	2.4
Barclays	5.3	na	na	na	5.4	na	na	4.9	4.6	4.7	4.9	na	na	na	na	na	0.0	2.4	1.8	2.2
Chmura Economics & Analytics	5.3	8.4	5.3	5.3	5.3	5.4	5.3 H	4.9	4.6	4.8 H	4.8	5.5	na	na	7.7 H	na	0.5	3.1	2.9	2.6
Comerica Bank	5.3	8.5	5.3	na	5.3	5.2	4.8	4.1	4.1	4.2	4.5	5.2	6.1	na	6.8	na	1.0	2.1	2.0	2.2
Economist Intelligence Unit	5.3	8.5	na	5.3	5.3	5.2	4.9	4.8	4.5	4.5	4.6	na	na	na	7.3	na	0.5	na	2.3	na
EY-Parthenon	5.3	na	na	na	4.9	na	na	na	na	4.0	na	na	na	na	na	na	0.8	2.3	2.0	2.1
KPMG	5.3	8.5	5.3	5.1	5.3	5.3	5.1	4.7	4.3	4.3	4.4	5.1	6.3	na	7.1	na	0.5	2.9	2.7	2.6
Loomis, Sayles & Company	5.3	8.5	5.3	5.3	5.5	5.5 H	5.3 H	5.0 H	4.6	4.5	4.7	5.3	6.3	4.6	7.2	116.8	1.1	2.5	2.1	1.9
Moody's Analytics	5.3	8.5	5.3	5.2	5.0	4.9	4.8	4.7	4.4	4.2	4.7	5.6	6.7	4.3	6.8	na	1.2	2.0	2.6	2.5
PNC Financial Services Corp.	5.3	8.5	5.3	na	5.3	5.2	5.1	4.8	4.7 H	4.6	4.7	na	7.1 H	5.9 H	7.3	117.2	-0.8	2.1	1.7	1.7
Regions Financial Corporation	5.3	8.5	5.3	5.3	5.4	5.4	5.1	4.5	4.3	4.2	4.4	5.2	6.2	4.5	7.0	116.1	1.0	2.7	3.1	3.0
Santander Capital Markets	5.3	8.5	5.3	5.4	5.4	5.3	5.1	4.9	4.5	4.5	4.7	5.4	6.5	3.9 L	7.2	115.5	1.1	2.9	2.9	2.6
Scotiabank Group	5.3	na	5.1	na	5.0	na	na	3.9	3.9	4.2	4.3	na	na	na	na	na	0.2	0.8 L	1.7	1.5
DePrince & Assoc.	5.2	8.3	5.3	5.2	5.3	5.3	5.2	4.9	4.6	4.6	4.7	5.6	6.6	4.8	7.1	117.6	1.0	2.6	2.8	2.6
MacroFin Analytics & Rutgers Bus School	5.2	8.4	5.1	5.3	5.2	5.3	5.1	4.8	4.2	4.4	4.5	5.2	5.8	4.3	7.1	115.5	1.0	2.3	2.5	2.5
MacroPolicy Perspectives	5.2	8.4	5.1	na	na	na	na	4.5	4.3	4.5	na	na	na	na	7.1	na	1.5	1.8	1.5	1.4
Bank of America	5.1	na	na	na	na	na	na	4.5	4.4	4.3	4.7	na	na	na	na	na	0.5	2.6	2.8	2.5
Daiwa Capital Markets America	5.1	8.3	na	na	4.9	na	na	4.1	3.7 L	3.9	4.2	na	na	na	6.6	116.0	-1.4	2.5	2.5	2.4
Fannie Mae	5.1	8.3	na	na	5.1	5.0	4.8	4.5	4.3	4.3	4.5	na	na	na	6.9	na	-1.5	2.6	2.0	2.1
GLC Financial Economics	5.1	8.2	5.1	5.0	5.0	4.8	4.7	4.2	4.3	4.3	4.5	5.1	6.1	4.3	6.4	113.3	1.2	2.9	2.6	2.2
Societe Generale	5.1	8.3	5.1	na	4.9	4.6	4.1	3.5 L	3.7 L	3.8 L	4.1 L	na	na	na	na	na	-1.8	1.8	2.2	2.0
Wells Fargo	5.1	8.3	5.1	5.1	4.8	4.4	3.9	3.7	3.7 L	3.9	4.2	5.1	6.1	4.5	6.7	na	-0.3	1.3	1.0 L	1.3 L
Via Nova Investment Mgt.	5.0	8.3	5.1	5.1	5.0	5.0	5.0	4.6	4.6	4.5	4.6	5.6	6.2	4.5	7.3	114.0	2.5 H	2.1	2.1	2.1
ING	4.9	na	na	na	na	na	na	4.1	4.0	4.0	4.4	na	na	na	na	na	-2.0 L	na	na	na
The Lonski Group	4.9	8.1	4.9	4.9	4.7	4.7	4.5	4.4	4.2	4.0	4.1 L	5.1	6.0	4.2	6.9	118.5	0.0	2.3	2.2	2.3
Georgia State University	4.5	7.6	na	na	4.5	4.2	4.1	3.9	4.0	4.3	4.4	5.2	6.3	na	7.2	na	-0.5	2.8	2.7	2.6
NatWest Markets	4.3	na	na	4.4	4.6	4.7	4.8	3.6	3.8	4.3	4.7	5.2	6.1	4.9	6.7	na	-1.5	1.8	1.1	1.8
TS Lombard	3.5 L	6.6 L	3.5 L	3.5 L	3.4 L	3.5 L	3.6 L	3.8	3.9	4.0	4.1 L	4.9 L	5.7 L	4.0	5.8 L	108.0 L	0.4	3.2 H	3.2	3.2 H
December Consensus	**5.2**	**8.3**	**5.2**	**5.1**	**5.1**	**5.1**	**4.9**	**4.5**	**4.3**	**4.3**	**4.5**	**5.3**	**6.4**	**4.6**	**7.1**	**115.9**	**0.3**	**2.3**	**2.3**	**2.2**
Top 10 Avg.	5.4	8.5	5.4	5.4	5.5	5.4	5.2	4.9	4.6	4.6	4.8	5.6	6.7	4.9	7.4	117.4	1.4	2.9	2.9	2.8
Bottom 10 Avg.	4.8	8.0	4.9	4.9	4.7	4.6	4.4	3.9	3.9	4.0	4.3	5.1	6.1	4.3	6.7	114.5	-1.1	1.7	1.7	1.7
November Consensus	5.2	8.4	5.3	5.2	5.2	5.1	4.9	4.5	4.3	4.3	4.5	5.4	6.4	4.6	7.1	117.2	0.3	2.3	2.4	2.2
Number of Forecasts Changed From A Month Ago:																				
Down	12	7	8	8	13	11	12	14	14	11	12	10	10	9	12	11	13	5	10	6
Same	21	17	14	9	14	9	10	14	13	13	11	7	6	7	6	3	12	14	13	18
Up	4	5	3	3	5	7	5	8	9	13	11	5	5	2	10	3	12	16	13	11
Diffusion Index	39%	47%	40%	38%	38%	43%	37%	42%	43%	53%	49%	39%	38%	31%	46%	26%	49%	66%	54%	57%

Third Quarter 2024

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term			Long-Term					Avg. For ---Qtr.---	(Q-Q % Change) (SAAR)			
	1 Federal Funds Rate	2 Prime Bank Rate	3 SOFR Rate	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Adv Fgn Econ $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index	E. PCE Price Index
Chan Economics	5.4 H	8.4	5.3	5.3	5.4	5.5 H	5.3 H	4.8	4.3	4.4	4.6	5.6	6.6	5.0	7.2	114.5	0.3	2.4	2.6	2.2
Goldman Sachs & Co.	5.4 H	na	na	na	5.0	na	na	4.8	4.6	4.6	4.6	na	na	na	na	na	1.7	2.3	2.4	2.3
J.P. Morgan Chase	5.4 H	na	na	na	na	na	na	4.3	4.1	4.2	4.6	na	na	na	na	na	0.5	2.5	2.7	2.3
Oxford Economics	5.4 H	8.5 H	5.4	na	5.5 H	5.4	5.2	4.8	4.0	4.3	4.6	4.6 L	na	na	7.1	117.7	0.5	2.3	2.2	2.2
Action Economics	5.3	8.4	5.8 H	5.3	5.3	5.1	4.9	4.7	4.5	4.5	4.7	5.4	6.4	4.3	7.6	118.8	1.3	1.4 L	2.4	1.7
Barclays	5.3	na	na	na	5.3	na	na	4.6	4.4	4.5	4.7	na	na	na	na	na	-0.5	2.8	2.6	2.6
BMO Capital Markets	5.3	8.4	5.3	5.3	5.5 H	5.4	4.9	4.1	4.1	4.2	4.4	5.4	6.5	5.0	7.2	117.4	1.3	2.2	2.4	2.2
Loomis, Sayles & Company	5.3	8.5 H	5.3	5.3	5.5 H	5.5 H	5.3 H	5.0	4.6	4.5	4.7	5.3	6.3	4.6	7.1	116.7	-1.5	1.9	1.2 L	1.2 L
Regions Financial Corporation	5.3	8.5 H	5.3	5.2	5.2	5.1	4.9	4.3	4.2	4.1	4.4	5.2	6.2	4.5	6.8	115.7	1.2	2.4	2.4	2.6
S&P Global Market Intelligence	5.3	8.4	5.3	na	5.1	4.8	4.8	4.4	4.1	4.2	4.4	na	na	na	6.8	na	1.1	2.5	3.3	2.7
Santander Capital Markets	5.3	8.5 H	5.3	5.3	5.2	5.1	4.9	4.7	4.4	4.3	4.7	5.5	6.6	3.8 L	6.9	115.0	0.8	2.7	2.7	2.3
PNC Financial Services Corp.	5.2	8.3	5.2	na	5.0	5.0	4.9	4.7	4.7	4.7	4.8	na	7.1	5.9 H	7.3	119.7 H	-1.4	2.0	1.6	1.6
RDQ Economics	5.2	8.3	5.2	5.7 H	5.1	5.0	4.6	4.3	4.4	4.4	4.4	6.0	7.2 H	4.6	6.9	116.2	-1.8 L	3.0	3.2	3.1
Comerica Bank	5.1	8.3	5.1	na	5.1	4.9	4.5	3.9	3.9	4.0	4.3	5.0	5.9	na	6.5	na	1.3	2.0	2.1	2.2
Economist Intelligence Unit	5.1	8.3	na	5.1	5.0	4.8	4.6	4.6	4.4	4.4	4.5	na	na	na	7.1	na	1.1	na	2.2	na
Fannie Mae	5.1	8.3	na	na	4.9	4.8	4.6	4.4	4.2	4.3	4.5	na	na	na	6.7	na	-0.5	2.2	2.1	2.0
Nomura Securities, Inc.	5.1	8.3	na	na	na	na	na	3.7	3.7	3.9	na	na	na	na	na	na	-1.1	2.0	2.8	2.5
The Northern Trust Company	5.1	8.3	5.1	5.2	5.1	4.9	4.7	4.3	4.4	4.5	4.8	5.6	6.7	4.8	7.0	114.0	1.3	2.2	2.3	2.3
Chmura Economics & Analytics	5.0	8.1	4.9	5.0	5.0	5.1	5.2	4.8	4.5	4.7	4.8	5.4	na	na	7.4	na	0.8	2.8	2.8	2.5
DePrince & Assoc.	5.0	8.1	5.0	5.0	5.0	5.0	4.9	4.7	4.6	4.6	4.7	5.7	6.6	4.8	7.0	117.3	1.8	2.5	2.7	2.5
EY-Parthenon	5.0	na	na	na	4.6	na	na	na	na	3.9	na	na	na	na	na	na	1.5	2.2	2.5	2.2
Moody's Analytics	5.0	8.2	5.0	4.9	4.7	4.7	4.6	4.5	4.3	4.1	4.6	5.6	6.6	4.3	6.7	na	1.5	1.8	2.3	2.3
Bank of America	4.9	na	na	na	na	na	na	4.3	4.3	4.3	4.7	na	na	na	na	na	0.5	2.7	2.5	2.4
KPMG	4.9	8.0	4.9	4.6	4.9	4.8	4.7	4.3	3.9	3.9	4.1	4.8	6.0	na	6.5	na	1.0	2.6	3.4 H	2.8
Scotiabank Group	4.8	na	4.6	na	4.2	na	na	3.7	3.8	4.0	4.2	na	na	na	na	na	0.8	1.5	3.2	1.9
Via Nova Investment Mgt.	4.8	8.0	4.8	4.9	4.8	4.8	4.8	5.1 H	5.1 H	5.1 H	5.1 H	6.2 H	6.8	5.1	7.9 H	112.0	2.5 H	2.1	2.1	2.1
GLC Financial Economics	4.7	7.8	4.6	4.7	4.6	4.6	4.4	4.0	4.2	4.2	4.5	5.1	6.0	4.3	6.2	116.1	2.1	1.4 L	2.2	2.3
MacroPolicy Perspectives	4.7	7.8	4.6	na	na	na	na	4.0	4.2	4.3	na	na	na	na	6.8	na	2.0	2.4	2.5	2.0
Daiwa Capital Markets America	4.6	7.8	na	na	4.4	na	na	3.7	3.5 L	3.6	4.3	na	na	na	6.3	115.0	1.0	2.4	2.5	2.4
MacroFin Analytics & Rutgers Bus School	4.6	7.8	4.5	4.7	4.5	4.7	4.8	4.7	4.0	4.2	4.4	5.1	5.7 L	4.1	6.9	115.3	1.3	2.2	2.3	2.4
Societe Generale	4.6	7.8	4.6	na	4.4	4.1	3.7	3.3	3.5 L	3.6	3.9 L	na	na	na	na	na	-0.5	1.8	2.2	1.9
ING	4.4	na	na	na	na	na	na	3.5	3.5 L	3.5 L	3.9 L	na	na	na	na	na	-1.7	na	na	na
The Lonski Group	4.4	7.6	4.4	4.4	4.2	4.2	4.1	4.0	4.0	3.9	4.1	5.0	5.8	4.1	6.7	118.7	0.8	2.1	2.1	2.2
Wells Fargo	4.4	7.5	4.4	4.4	4.0	3.6	3.4 L	3.4	3.5 L	3.7	4.0	4.9	5.9	4.3	6.4	na	-1.5	1.4 L	1.3	1.4
Georgia State University	4.0	7.2	na	na	3.9	3.7	3.5	3.5	3.7	4.0	4.3	5.0	6.1	na	6.8	na	0.4	2.4	3.3	2.6
TS Lombard	3.5	6.6 L	3.5 L	3.5	3.4 L	3.5 L	3.6	3.8	3.9	4.0	4.1	4.9	5.7 L	4.0	5.8 L	110.0 L	1.5	3.4 H	3.4 H	3.4 H
NatWest Markets	3.3 L	na	na	3.4 L	3.6	3.7	3.8	3.2 L	3.5 L	4.1	4.6	4.9	5.8	4.6	6.4	na	-0.5	1.6	1.7	2.0
December Consensus	**4.9**	**8.1**	**4.9**	**4.9**	**4.8**	**4.7**	**4.6**	**4.2**	**4.1**	**4.2**	**4.5**	**5.3**	**6.3**	**4.6**	**6.9**	**115.9**	**0.6**	**2.2**	**2.5**	**2.3**
Top 10 Avg.	5.3	8.4	5.3	5.3	5.3	5.2	5.0	4.8	4.6	4.6	4.8	5.6	6.7	4.9	7.3	117.4	1.7	2.8	3.1	2.7
Bottom 10 Avg.	4.3	7.6	4.5	4.5	4.1	4.2	4.0	3.6	3.7	3.8	4.1	4.9	5.9	4.2	6.4	114.4	-1.1	1.7	1.9	1.8
November Consensus	4.9	8.0	4.9	4.8	4.8	4.7	4.6	4.2	4.1	4.2	4.5	5.2	6.3	4.5	6.8	116.6	1.0	2.2	2.5	2.3
Number of Forecasts Changed From A Month Ago:																				
Down	11	7	7	7	14	14	12	12	11	10	12	8	8	10	13	8	17	10	8	8
Same	22	16	15	9	12	8	7	13	16	15	10	7	7	4	6	5	12	16	16	15
Up	4	6	3	4	6	5	8	11	9	12	12	7	6	4	9	4	8	9	12	12
Diffusion Index	41%	48%	42%	43%	38%	33%	43%	49%	47%	53%	50%	48%	45%	33%	43%	38%	38%	49%	56%	56%

Fourth Quarter 2024

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term			Long-Term					Avg. For Qtr.	(Q-Q % Change) (SAAR)			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	A.	B.	C.	D.	E.
	Federal Funds Rate	Prime Bank Rate	SOFR Rate	Com. Paper 1-Mo.	Treas. Bills 3-Mo.	Treas. Bills 6-Mo.	Treas. Bills 1-Yr.	Treas. Notes 2-Yr.	Treas. Notes 5-Yr.	Treas. Notes 10-Yr.	Treas. Bond 30-Yr.	Aaa Corp. Bond	Baa Corp. Bond	State & Local Bonds	Home Mtg. Rate	Fed's Adv Fgn Econ $ Index	Real GDP	GDP Price Index	Cons. Price Index	PCE Price Index
Barclays	5.3 H	na	na	na	5.1	na	na	4.4	4.3	4.3	4.5	na	na	na	na	na	1.0	2.7	2.6	2.6
Chan Economics	5.2	8.2	5.1	5.1	5.2	5.3 H	5.1 H	4.6	4.1	4.2	4.4	5.4	6.4	4.8	7.0	114.3	0.8	2.3	2.5	2.1
Goldman Sachs & Co.	5.1	na	na	na	4.8	na	na	4.6	4.5	4.6	4.5	na	na	na	na	na	1.9	2.1	2.4	2.1
Loomis, Sayles & Company	5.1	8.3 H	5.1	5.1	5.2	5.1	4.9	4.6	4.6	4.5	4.7	5.3	6.3	4.6	6.9	116.6	-2.2 L	1.9	1.5 L	1.5 L
Regions Financial Corporation	5.1	8.3 H	5.1	5.2 H	4.8	4.8	4.8	4.1	4.1	4.1	4.3	5.1	6.2	4.4	6.7	115.5	1.6	2.4	2.4	2.5
S&P Global Market Intelligence	5.1	8.2	5.0	na	4.8	4.5	4.5	4.1	3.9	4.0	4.3	na	na	na	6.5	na	1.3	2.3	2.0	2.1
Santander Capital Markets	5.1	8.3 H	5.1	5.1	4.7	4.6	4.5	4.4	4.2	4.1	4.4	5.2	6.3	3.6 L	6.6	114.0	1.1	2.5	2.5	2.1
Action Economics	5.0	8.2	5.7 H	5.0	5.1	4.9	4.6	4.6	4.5	4.5	4.6	5.3	6.3	4.3	7.6 H	119.0	1.6	1.5	2.4	1.8
BMO Capital Markets	5.0	8.2	5.0	5.1	5.2	5.1	4.6	3.9	4.0	4.1	4.3	5.3	6.4	4.8	7.1	117.6	1.5	2.0	2.2	2.0
Fannie Mae	5.0	8.1	na	na	4.6	4.6	4.4	4.3	4.2	4.3	4.4	na	na	na	6.6	na	0.5	2.2	2.6	2.3
J.P. Morgan Chase	5.0	na	na	na	na	na	na	3.9	3.9	4.0	4.5	na	na	na	na	na	0.8	2.3	2.4	2.0
Oxford Economics	5.0	8.2	5.0	na	5.3 H	5.2	4.9	4.5	3.7	4.1	4.4	4.2 L	na	na	6.9	116.1	0.7	2.3	1.8	2.2
PNC Financial Services Corp.	5.0	8.1	5.0	na	4.7	4.6	4.6	4.6	4.7	4.8 H	5.0	na	7.1 H	5.9 H	7.2	122.0 H	-1.2	1.9	1.8	1.6
Comerica Bank	4.8	8.0	4.8	na	4.7	4.5	4.0	3.5	3.5	3.7	4.0	4.7	5.6 L	na	6.0	na	1.5	2.0	2.1	2.2
Economist Intelligence Unit	4.8	8.0	na	4.8	4.8	4.6	4.5	4.4	4.2	4.3	4.5	na	na	na	7.0	na	1.5	na	2.1	na
EY-Parthenon	4.8	na	na	na	4.4	na	na	na	na	3.8	na	na	na	na	na	na	1.8	2.1	2.2	2.1
Moody's Analytics	4.8	7.9	4.7	4.7	4.5	4.4	4.4	4.3	4.2	4.1	4.5	5.5	6.5	4.2	6.5	na	1.5	1.9	2.2	2.3
DePrince & Assoc.	4.7	7.8	4.7	4.7	4.7	4.7	4.6	4.5	4.5	4.5	4.6	5.7	6.6	4.9	6.8	117.1	2.1	2.4	2.6	2.4
RDQ Economics	4.7	7.8	4.7	5.1	4.6	4.6	4.4	4.2	4.3	4.3	5.3 H	5.9 H	7.0	5.6	6.8	115.1	0.9	2.9	3.0	3.0
Bank of America	4.6	na	na	na	na	na	na	4.0	4.2	4.3	4.8	na	na	na	na	na	1.0	2.5	1.9	2.2
Nomura Securities, Inc.	4.6	7.8	na	na	na	na	na	3.2	3.3 L	3.7	na	na	na	na	na	na	-1.9	1.6	2.7	2.3
The Northern Trust Company	4.6	7.8	4.6	4.7	4.5	4.3	4.2	3.9	4.2	4.3	4.6	5.6	6.7	4.7	6.8	112.0	1.5	2.1	2.2	2.2
Chmura Economics & Analytics	4.5	7.7	4.5	4.6	4.6	4.8	4.8	4.6	4.4	4.6	4.8	5.4	na	na	7.0	na	1.9	2.5	2.6	2.4
KPMG	4.5	7.6	4.5	4.1	4.4	4.4	4.2	3.9	3.5	3.6	3.9	4.5	5.7	na	6.0	na	2.0	2.4	2.1	2.2
Via Nova Investment Mgt.	4.5	7.8	4.6	4.6	4.5	4.5	4.5	4.8 H	4.8 H	4.8 H	4.8	5.9 H	6.6	4.8	7.6 H	110.0 L	2.5	2.1	2.0	2.1
GLC Financial Economics	4.3	7.4	4.3	4.3	4.3	4.2	4.1	3.7	4.1	4.1	4.4	4.9	5.9	4.3	6.0	115.9	1.6	1.6	2.0	2.2
MacroPolicy Perspectives	4.2	7.4	4.2	na	na	na	na	3.5	4.0	4.3	na	na	na	na	6.5	na	2.3	2.5	2.7	2.1
Societe Generale	4.2	7.3	4.2	na	3.9	3.6	3.3	3.1 L	3.5	3.6	3.9	na	na	na	na	na	3.7 H	1.8	2.2	1.8
Daiwa Capital Markets America	4.1	7.3	na	na	4.0	na	na	3.4	3.3 L	3.5 L	4.2	na	na	na	6.1	115.0	2.0	2.3	2.4	2.3
MacroFin Analytics & Rutgers Bus School	4.1	7.3	4.0	4.3	3.9	4.2	4.4	4.5	3.8	4.0	4.4	5.0	5.6 L	3.9	6.7	115.1	1.6	2.2	2.1	2.2
Scotiabank Group	4.0	na	3.8	na	3.7	na	na	3.5	3.6	4.0	4.2	na	na	na	na	na	1.2	1.1 L	2.9	2.9
ING	3.9	na	na	na	na	na	na	3.3	3.4	3.5 L	3.9	na	na	na	na	na	1.0	na	na	na
The Lonski Group	3.9	7.1	3.9	4.0	3.7	3.8	3.7	3.7	3.8	3.9	4.0	5.0	5.8	4.1	6.6	119.3	1.5	2.2	2.1	2.0
Georgia State University	3.6	6.8	na	na	3.5	3.2 L	3.1 L	3.4	3.4	3.7	4.0	4.7	5.9	na	6.6	na	0.8	2.2	2.0	2.0
Wells Fargo	3.6	6.8	3.6	3.6	3.4 L	3.3	3.2	3.2	3.3 L	3.5 L	3.8 L	4.7	5.7	4.1	6.1	na	0.3	2.6	3.1	2.6
TS Lombard	3.5	6.6 L	3.5 L	3.5	3.4 L	3.5	3.6	3.8	3.9	4.0	4.1	4.9	5.7	4.0	5.8 L	112.0	2.0	3.2 H	3.2 H	3.2 H
NatWest Markets	3.1 L	na	na	3.2 L	3.4 L	3.5	3.6	3.1 L	3.4	4.0	4.6	4.8	5.7	4.5	6.3	na	1.5	1.4	2.7	2.4
December Consensus	**4.6**	**7.7**	**4.6**	**4.5**	**4.5**	**4.4**	**4.3**	**4.0**	**4.0**	**4.1**	**4.4**	**5.1**	**6.2**	**4.5**	**6.7**	**115.7**	**1.2**	**2.2**	**2.3**	**2.2**
Top 10 Avg.	5.1	8.2	5.1	5.0	5.0	4.9	4.7	4.6	4.5	4.5	4.8	5.5	6.6	4.9	7.1	117.4	2.2	2.6	2.8	2.6
Bottom 10 Avg.	3.8	7.2	4.1	4.1	3.7	3.8	3.7	3.3	3.4	3.7	4.0	4.7	5.8	4.1	6.2	113.9	-0.1	1.7	1.9	1.9
November Consensus	4.5	7.6	4.5	4.4	4.5	4.4	4.3	3.9	3.9	4.0	4.3	5.1	6.2	4.4	6.6	116.4	1.5	2.2	2.5	2.3
Number of Forecasts Changed From A Month Ago:																				
Down	9	5	5	4	15	15	12	9	8	6	9	8	8	8	10	8	14	10	11	8
Same	20	17	14	11	12	8	11	14	15	16	11	8	7	5	8	4	17	16	18	16
Up	8	7	6	5	5	4	4	11	11	13	12	6	6	5	10	5	6	9	7	11
Diffusion Index	49%	53%	52%	53%	34%	30%	35%	53%	54%	60%	55%	45%	45%	42%	50%	41%	39%	49%	44%	54%

First Quarter 2025

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term			Long-Term					Avg. For ---Qtr.---	(Q-Q % Change) (SAAR)			
	1 Federal Funds Rate	2 Prime Bank Rate	3 SOFR Rate	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Adv Fgn Econ $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index	E. PCE Price Index
Barclays	5.1 H	na	na	na	4.9	na	na	na	na	na	na	na	na	na	na	na	1.0	3.0 H	3.1 H	2.8 H
Chan Economics	4.9	7.9	4.8	4.8 H	4.9	5.0 H	4.8 H	4.3	3.8	3.9	4.1	5.1	6.1	4.5	6.7	114.0	1.5	2.2	2.4	2.0
Goldman Sachs & Co.	4.9	na	na	na	4.6	na	na	4.5	4.4	4.5	4.5	na	na	na	na	na	1.9	2.2	2.5	2.2
Action Economics	4.8	7.9	5.4 H	4.8 H	4.8	4.6	4.4	4.4	4.4	4.4	4.6	5.3	6.3	4.2	7.5	119.2	1.6	1.8	2.4	1.8
BMO Capital Markets	4.8	7.9	4.8	4.8 H	5.0 H	4.9	4.4	3.8	3.9	4.1	4.2	5.2	6.3	4.8	7.1	117.8	1.7	2.1	2.3	2.1
Oxford Economics	4.8	8.0 H	4.8	na	5.0 H	4.9	4.7	4.4	3.4	3.9	3.8	4.0 L	na	na	6.7	114.3	1.2	2.3	2.1	2.1
Fannie Mae	4.7	7.8	na	na	4.4	4.4	4.3	4.2	4.2	4.3	4.4	na	na	na	6.4	na	1.2	2.1	2.8	2.3
PNC Financial Services Corp.	4.7	7.8	4.7	na	4.4	4.2	4.3	4.5	4.7	4.9 H	5.2 H	na	7.1 H	6.0 H	7.2	123.4 H	0.4 L	2.1	2.0	1.8
S&P Global Market Intelligence	4.7	7.8	4.6	na	4.4	4.1	4.1	3.8	3.6	3.8	4.1	na	na	na	6.1	na	1.5	2.1	0.8 L	1.5
Economist Intelligence Unit	4.6	7.8	na	4.6	4.6	4.4	4.3	4.3	4.1	4.0	4.4	na	na	na	6.7	na	1.9	na	2.2	na
Loomis, Sayles & Company	4.6	7.8	4.6	4.6	4.7	4.6	4.4	4.0	4.4	4.5	4.7	5.3	6.3	4.6	6.8	116.5	1.0	2.1	2.0	2.0
Regions Financial Corporation	4.6	7.8	4.5	4.7	4.5	4.6	4.7	3.8	3.9	4.0	4.3	5.1	6.1	4.3	6.5	115.1	1.7	2.2	2.2	2.3
Santander Capital Markets	4.6	7.8	4.6	4.6	4.2	4.1	4.0	4.0	3.8	3.8	4.1	4.9	6.0	3.4 L	6.2	113.0	1.3	2.8	2.4	2.1
Moody's Analytics	4.5	7.7	4.5	4.4	4.3	4.2	4.3	4.2	4.1	4.0	4.5	5.5	6.5	4.2	6.4	na	1.6	2.2	2.2	2.3
Bank of America	4.4	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	1.5	2.6	2.4	2.5
Comerica Bank	4.4	7.6	4.4	na	4.2	4.1	3.6	3.1	3.3	3.5	3.9	4.7	5.5 L	na	5.8 L	na	1.5	1.9	2.0	2.0
J.P. Morgan Chase	4.4	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.0	2.3	2.5	2.1
DePrince & Assoc.	4.3	7.5	4.4	4.4	4.4	4.4	4.3	4.3	4.4	4.5	4.6	5.7	6.6	4.8	6.7	116.9	2.4	2.3	2.6	2.4
EY-Parthenon	4.3	na	na	na	3.9	na	na	na	na	3.7	na	na	na	na	na	na	2.3	2.2	2.1	2.1
Via Nova Investment Mgt.	4.3	7.5	4.3	4.4	4.2	4.3	4.4	4.7 H	4.9 H	4.9 H	5.0	6.0 H	6.6	4.9	7.7 H	110.0 L	2.5	2.2	2.0	2.1
Chmura Economics & Analytics	4.2	7.3	4.2	4.2	4.3	4.4	4.4	4.6	4.4	4.6	4.8	5.3	na	na	6.7	na	2.5	2.4	2.5	2.4
GLC Financial Economics	4.2	7.3	4.3	4.2	4.2	4.2	4.0	3.8	3.7	3.8	4.1	4.8	6.0	4.3	5.8 L	115.2	2.0	1.6	2.0	2.2
KPMG	4.2	7.3	4.1	3.8	4.0	3.9	3.8	3.5	3.3	3.5	3.8	4.4	5.6	na	5.8 L	na	1.9	2.1	0.9	1.6
Nomura Securities, Inc.	4.1	7.3	na	na	na	na	na	3.0	3.2	3.6	na	na	na	na	na	na	0.4 L	1.6	2.8	2.3
The Northern Trust Company	4.1	7.3	4.1	4.2	4.0	3.8	3.8	3.8	3.9	4.1	4.4	5.4	6.5	4.5	6.6	111.0	1.6	2.1	2.1	2.1
Daiwa Capital Markets America	3.9	7.0	na	na	3.8	na	na	3.1	3.1	3.3	4.1	na	na	na	5.9	115.0	1.6	2.4	2.5	2.2
MacroPolicy Perspectives	3.9	7.0	3.8	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na
Georgia State University	3.6	6.7	na	na	3.4	3.1 L	3.1	3.3	3.3	3.7	4.0	4.7	5.8	na	6.2	na	1.8	1.9	1.5	1.4 L
MacroFin Analytics & Rutgers Bus School	3.6	6.9	3.5	3.8	3.4	3.7	4.0	4.3	3.7	3.9	4.3	4.8	5.6	3.8	6.6	114.9	1.8	2.0	2.1	2.1
Societe Generale	3.6	6.8	3.6	na	3.4	3.2	3.0 L	2.9 L	2.7 L	3.2 L	3.5 L	na	na	na	na	na	3.6 H	2.0	2.2	1.8
Scotiabank Group	3.5	na	3.3	na	3.3	na	na	3.4	3.5	4.0	4.2	na	na	na	na	na	1.3	2.1	2.0	2.5
The Lonski Group	3.5	6.7	3.5	3.5	3.6	3.7	3.6	3.6	3.7	3.8	4.0	4.9	5.7	4.0	6.4	119.4	1.8	2.2	2.1	2.0
ING	3.4	na	na	na	na	na	na	3.2	3.4	3.5	3.9	na	na	na	na	na	1.5	na	na	na
NatWest Markets	3.1 L	na	na	3.2	3.4	3.5	3.6	na	na	na	na	na	na	na	na	na	2.0	1.4 L	2.5	2.0
Wells Fargo	3.1 L	6.3 L	3.1 L	3.1 L	3.1 L	3.1 L	3.1	3.1	3.2	3.4	3.8	4.6	5.6	4.0	5.9	na	1.8	2.7	3.1 H	2.7
December Consensus	**4.2**	**7.4**	**4.3**	**4.2**	**4.2**	**4.1**	**4.1**	**3.9**	**3.8**	**4.0**	**4.3**	**5.0**	**6.1**	**4.4**	**6.5**	**115.7**	**1.7**	**2.2**	**2.2**	**2.1**
Top 10 Avg.	4.8	7.9	4.7	4.6	4.7	4.6	4.5	4.4	4.4	4.5	4.7	5.4	6.4	4.7	7.0	117.3	2.3	2.5	2.7	2.5
Bottom 10 Avg.	3.5	6.9	3.8	3.9	3.5	3.6	3.6	3.2	3.2	3.5	3.9	4.7	5.8	4.1	6.1	113.9	1.1	1.8	1.7	1.8
November Consensus	4.1	7.2	4.1	4.1	4.1	4.1	4.0	3.8	3.8	3.9	4.2	5.0	6.1	4.4	6.4	116.7	1.9	2.3	2.3	2.2
Number of Forecasts Changed From A Month Ago:																				
Down	6	4	4	2	8	9	7	6	6	7	4	7	6	7	8	7	11	7	8	8
Same	19	16	13	11	14	9	9	14	14	12	14	5	6	6	5	5	12	14	13	11
Up	10	7	6	5	8	7	9	8	8	10	10	7	6	2	11	3	9	9	10	11
Diffusion Index	56%	56%	54%	58%	50%	46%	54%	54%	54%	55%	61%	50%	50%	33%	56%	37%	47%	53%	53%	55%

International Interest Rate And Foreign Exchange Rate Forecasts

United States

	Fed Fund Target Rate			10 Yr. Gov't Bond Yield %			Fed's AFE $ Index		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	5.13	5.13	5.13	5.00	4.85	4.35	--	--	--
BMO Capital Markets	5.38	5.38	4.88	4.37	4.26	4.13	117.2	117.2	117.0
ING Financial Markets	5.38	4.88	3.88	4.25	4.00	3.50	116.2	114.0	109.1
Moody's Analytics	5.37	5.38	5.09	4.66	4.33	4.13	--	--	--
Northern Trust	5.38	5.38	4.63	4.70	4.70	4.30	117.5	116.0	112.0
Oxford Economics	5.38	5.38	5.35	4.72	4.65	4.27	118.8	119.4	117.7
S&P Global Market Intelligence	--	--	--	4.64	4.43	4.01	--	--	--
Scotiabank	5.38	5.13	3.88	4.50	4.20	4.00	--	--	--
TS Lombard	4.75	3.50	3.50	4.25	4.00	4.00	110.0	108.0	112.0
Wells Fargo	5.38	5.38	4.38	4.30	3.85	3.65	--	--	--
December Consensus	**5.28**	**5.06**	**4.52**	**4.54**	**4.33**	**4.03**	**115.9**	**114.9**	**113.6**
High	5.38	5.38	5.35	5.00	4.85	4.35	118.8	119.4	117.7
Low	4.75	3.50	3.50	4.25	3.85	3.50	110.0	108.0	109.1
Last Months Avg.	5.49	5.36	4.52	4.64	4.39	3.92	119.3	116.4	112.7

Japan

	Policy-Rate Balance Rate			10 Yr. Gov't Bond Yield %			Yen per US$		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	-0.10	0.00	0.20	0.90	0.95	1.00	153.0	152.0	145.0
BMO Capital Markets	-0.10	-0.10	-0.10	0.96	0.98	1.00	148.0	146.0	141.0
ING Financial Markets	-0.10	0.00	0.00	1.00	1.00	1.20	140.0	135.0	130.0
Moody's Analytics	-0.10	-0.10	0.00	0.90	0.90	0.90	148.2	144.0	133.6
Nomura Securities	--	--	--	--	--	--	148.0	140.0	135.0
Northern Trust	-0.10	-0.10	0.10	0.80	0.80	1.00	149.0	146.0	140.0
Oxford Economics	-0.04	-0.04	0.00	0.88	0.91	0.87	150.4	152.5	145.0
S&P Global Market Intelligence	--	--	--	--	--	--	148.9	146.4	141.0
Scotiabank	--	--	--	--	--	--	150.0	150.0	140.0
TS Lombard	0.00	0.00	-0.10	0.65	0.40	0.40	145.0	142.4	147.6
Wells Fargo	-0.10	-0.10	0.00	0.95	0.95	0.85	--	--	--
December Consensus	**-0.08**	**-0.06**	**0.01**	**0.88**	**0.86**	**0.90**	**148.1**	**145.4**	**139.8**
High	0.00	0.00	0.20	1.00	1.00	1.20	153.0	152.5	147.6
Low	-0.10	-0.10	-0.10	0.65	0.40	0.40	140.0	135.0	130.0
Last Months Avg.	-0.08	-0.06	-0.05	0.85	0.80	0.66	147.2	142.6	135.3

United Kingdom

	Official Bank Rate			10 Yr. Gilt Yields %			US$ per Pound Sterling		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	5.25	5.25	4.25	4.10	4.10	4.00	1.21	1.23	1.30
BMO Capital Markets	5.25	5.08	4.58	4.39	4.30	4.13	1.26	1.26	1.27
ING Financial Markets	5.25	5.25	4.25	4.25	4.25	3.50	1.23	1.24	1.28
Moody's Analytics	5.25	5.25	5.06	4.26	3.93	3.73	1.25	1.26	1.26
Nomura Securities	--	--	--	--	--	--	1.27	1.28	1.30
Northern Trust	5.25	5.25	4.75	4.30	4.25	3.85	1.24	1.26	1.30
Oxford Economics	5.25	5.25	5.09	4.42	4.39	4.35	1.21	1.21	1.22
S&P Global Market Intelligence	--	--	--	--	--	--	1.22	1.23	1.25
Scotiabank	5.25	4.75	4.25	--	--	--	1.25	1.25	1.30
TS Lombard	5.25	4.25	2.25	4.10	3.85	3.85	1.27	1.20	1.15
Wells Fargo	5.25	4.75	3.75	4.20	3.90	3.55	--	--	--
December Consensus	**5.25**	**5.01**	**4.25**	**4.25**	**4.12**	**3.87**	**1.24**	**1.24**	**1.26**
High	5.25	5.25	5.09	4.42	4.39	4.35	1.27	1.28	1.30
Low	5.25	4.25	2.25	4.10	3.85	3.50	1.21	1.20	1.15
Last Months Avg.	5.28	5.09	4.43	4.52	4.28	3.88	1.22	1.23	1.24

Switzerland

	SNB Policy Rate			10 Yr. Gov't Bond Yield %			CHF per US$		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	1.75	1.75	1.25	--	--	--	0.91	0.92	0.91
BMO Capital Markets	1.75	1.75	1.75	--	--	--	0.87	0.86	0.85
ING Financial Markets	1.75	1.75	1.75	1.10	1.10	1.10	0.91	0.90	0.87
Moody's Analytics	2.00	2.00	2.00	1.46	1.96	2.05	0.89	0.88	0.84
Nomura Securities	--	--	--	--	--	--	0.88	0.87	0.86
Northern Trust	1.75	1.75	1.50	1.00	1.00	0.90	0.89	0.87	0.85
Oxford Economics	1.75	1.75	1.63	1.15	1.25	1.34	0.91	0.93	0.92
S&P Global Market Intelligence	--	--	--	--	--	--	0.92	0.91	0.89
Scotiabank	--	--	--	--	--	--	0.89	0.89	0.89
TS Lombard	1.75	1.50	1.25	0.80	0.55	0.55	0.90	0.90	0.90
Wells Fargo	1.75	1.50	1.25	--	--	--	--	--	--
December Consensus	**1.78**	**1.72**	**1.55**	**1.10**	**1.17**	**1.19**	**0.90**	**0.89**	**0.88**
High	2.00	2.00	2.00	1.46	1.96	2.05	0.92	0.93	0.92
Low	1.75	1.50	1.25	0.80	0.55	0.55	0.87	0.86	0.84
Last Months Avg.	1.79	1.75	1.59	1.29	1.31	1.29	0.91	0.90	0.89

Canada

	O/N MMkt Financing Rate			10 Yr. Gov't Bond Yield %			C$ per US$		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	5.25	5.25	5.00	--	--	--	1.39	1.38	1.36
BMO Capital Markets	5.00	5.00	4.50	3.64	3.58	3.54	1.33	1.31	1.28
ING Financial Markets	5.00	4.50	3.50	3.50	3.25	3.00	1.35	1.33	1.27
Moody's Analytics	5.00	5.00	4.49	4.39	4.19	4.14	1.36	1.32	1.27
Nomura Securities	--	--	--	--	--	--	1.34	1.33	1.31
Northern Trust	5.00	5.00	4.25	3.75	3.70	3.20	1.38	1.34	1.30
Oxford Economics	5.00	5.00	4.63	4.01	3.97	3.91	1.37	1.38	1.37
S&P Global Market Intelligence	--	--	--	--	--	--	1.35	1.33	1.30
Scotiabank	5.00	4.75	4.00	3.85	3.75	3.65	1.33	1.33	1.28
TS Lombard	5.00	4.00	2.75	3.50	2.25	2.25	1.35	1.35	1.35
Wells Fargo	5.00	4.50	4.00	3.60	3.50	3.30	--	--	--
December Consensus	**5.03**	**4.78**	**4.12**	**3.78**	**3.52**	**3.37**	**1.36**	**1.34**	**1.31**
High	5.25	5.25	5.00	4.39	4.19	4.14	1.39	1.38	1.37
Low	5.00	4.00	2.75	3.50	2.25	2.25	1.33	1.31	1.27
Last Months Avg.	5.03	4.88	4.17	3.91	3.76	3.39	1.35	1.33	1.30

International Interest Rate And Foreign Exchange Rate Forecasts

Australia

	Official Cash Rate			10 Yr. Gov't Bond Yield %			US$ per A$		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	4.35	4.35	3.85	--	--	--	0.63	0.64	0.66
BMO Capital Markets	4.35	4.10	3.60	--	--	--	0.66	0.66	0.67
ING Financial Markets	4.35	4.10	3.60	4.80	4.30	3.70	0.63	0.66	0.72
Moody's Analytics	4.27	4.35	4.10	5.12	4.90	4.36	0.64	0.66	0.72
Nomura Securities	--	--	--	--	--	--	0.68	0.69	0.71
Northern Trust	4.35	4.35	3.85	4.60	4.50	4.10	0.64	0.66	0.68
Oxford Economics	4.40	4.60	4.60	4.60	4.76	4.41	0.64	0.64	0.67
S&P Global Market Intelligence	--	--	--	--	--	--	0.64	0.66	0.69
Scotiabank	--	--	--	--	--	--	0.66	0.66	0.68
TS Lombard	4.10	3.75	2.75	4.40	3.20	3.20	0.65	0.65	0.65
Wells Fargo	4.35	4.35	4.10	--	--	--	--	--	--
December Consensus	**4.32**	**4.24**	**3.81**	**4.70**	**4.33**	**3.95**	**0.65**	**0.66**	**0.69**
High	4.40	4.60	4.60	5.12	4.90	4.41	0.68	0.69	0.72
Low	4.10	3.75	2.75	4.40	3.20	3.20	0.63	0.64	0.65
Last Months Avg.	4.24	4.12	3.76	4.59	4.27	3.69	0.65	0.66	0.68

Euro area

	Main Refinancing Rate			US$ per Euro		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	4.50	4.50	3.50	1.05	1.06	1.09
BMO Capital Markets	4.50	4.25	3.75	1.10	1.11	1.12
ING Financial Markets	4.50	4.25	3.75	1.08	1.10	1.15
Moody's Analytics	4.50	4.50	4.22	1.04	1.06	1.09
Nomura Securities	--	--	--	1.11	1.12	1.14
Northern Trust	4.50	4.25	3.75	1.07	1.10	1.14
Oxford Economics	4.50	4.50	3.75	1.05	1.05	1.06
S&P Global Market Intelligence	--	--	--	1.07	1.09	1.12
Scotiabank	4.50	4.25	3.75	1.10	1.10	1.12
TS Lombard	4.00	2.75	2.75	1.10	1.10	1.10
Wells Fargo	4.00	3.75	3.25	--	--	--
December Consensus	**4.39**	**4.11**	**3.61**	**1.08**	**1.09**	**1.11**
High	4.50	4.50	4.22	1.11	1.12	1.15
Low	4.00	2.75	2.75	1.04	1.05	1.06
Last Months Avg.	4.38	4.22	3.56	1.05	1.06	1.09

10 Yr. Gov't Bond Yields %

	Germany			France			Italy			Spain		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	2.70	2.65	2.25	--	--	--	--	--	--	--	--	--
BMO Capital Markets	2.60	2.49	2.28	--	--	--	--	--	--	--	--	--
ING Financial Markets	2.40	2.30	2.30	3.30	3.20	3.30	4.70	4.40	4.50	3.85	3.60	3.70
Moody's Analytics	2.73	2.67	2.60	3.28	3.15	3.02	4.60	4.60	4.53	3.84	3.77	3.75
Northern Trust	2.65	2.50	2.10	3.15	3.00	2.60	4.35	4.25	3.85	3.60	3.50	3.10
Oxford Economics	2.80	2.73	2.44	3.37	3.29	2.91	4.82	4.72	4.43	3.89	3.80	3.55
TS Lombard	2.40	2.15	2.15	2.75	2.50	2.50	3.70	3.45	3.45	3.15	2.90	2.90
Wells Fargo	2.55	2.50	2.45	--	--	--	--	--	--	--	--	--
December Consensus	**2.60**	**2.50**	**2.32**	**3.17**	**3.03**	**2.87**	**4.43**	**4.28**	**4.15**	**3.67**	**3.51**	**3.40**
High	2.80	2.73	2.60	3.37	3.29	3.30	4.82	4.72	4.53	3.89	3.80	3.75
Low	2.40	2.15	2.10	2.75	2.50	2.50	3.70	3.45	3.45	3.15	2.90	2.90
Last Months Avg.	2.76	2.63	2.44	3.27	3.09	2.88	4.49	4.31	4.10	3.76	3.60	3.42

Consensus Forecasts
10-year Bond Yields vs U.S. Yield

	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-3.68	-3.66	-3.47	-3.13
United Kingdom	-0.13	-0.29	-0.21	-0.16
Switzerland	-3.49	-3.44	-3.16	-2.85
Canada	-0.75	-0.76	-0.80	-0.66
Australia	0.08	0.16	0.00	-0.08
Germany	-1.83	-1.94	-1.83	-1.71
France	-1.27	-1.37	-1.30	-1.17
Italy	-0.08	-0.11	-0.04	0.12
Spain	-0.89	-0.87	-0.81	-0.63

Consensus Forecasts
Policy Rates vs U.S. Target Rate

	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-5.48	-5.36	-5.01	-4.51
United Kingdom	-0.13	-0.03	-0.05	-0.28
Switzerland	-3.63	-3.50	-3.34	-2.98
Canada	-0.38	-0.25	-0.28	-0.40
Australia	-1.03	-0.97	-0.82	-0.72
Euro area	-0.88	-0.89	-0.95	-0.92

Special Questions:

1. What is your estimate of the long-term neutral fed funds rate?

Consensus	2.90%
Top 10	3.72%
Bottom 10	2.29%

2. Have financial conditions tightened sufficiently to delay/prevent further policy rate increases? Yes 97% No 3%

3. What probability do you attach to a recession beginning over the next 12 months in the:

	US	euro area	UK
Consensus	**44%**	**55%**	**58%**
Top 10	59%	66%	67%
Bot 10	29%	44%	48%

4 a. Does your outlook for China's economy pose meaningful risks to the outlook for global growth? Yes 74% No 26%

b. Do you think recent policy measures in China will boost its growth rate? Yes 37% No 63%

5 a. Has the Federal Reserve completed its tightening cycle? Yes 100% No 0%

b. Has the European Central Bank completed its tightening cycle? Yes 91% No 9%

c. Has the Bank of England completed its tightening cycle? Yes 91% No 9%

6. When will the first hike in the BoJ's short-term policy rate occur?

Q4 2023	0%
Q1 2024	5%
Q2 2024	53%
Q3 2024	21%
Later	21%

Viewpoints:

A Sampling of Views on the Economy, Financial Markets and Government Policy Excerpted from Recent Reports Issued by our Blue Chip Panel Members and Others

FOMC: On Hold in Restrictive Territory
(Lawrence Werther, Daiwa Capital Markets America)

Since the Fed embarked on its aggressive rate hike campaign in March 2022, we have held the view that a restrictive stance of monetary policy would be required to tame rapid inflation and prevent erosion in inflation expectations of businesses and households. For much of the past year, we had anticipated that the current campaign would culminate in a final increase of 25 basis points in the target range for the federal funds rate to 5.50 to 5.75 percent, with the last change occurring in late 2023, before maintaining the policy rate in restrictive territory for several months. In light of more recent developments, we have become less confident in anticipating any further increase. The FOMC last hiked the federal funds rate in July, and comments by various officials since then, in our view, have turned decidedly more cautious. Moreover, while inflation is still well above target and various indicators suggest that supply and demand imbalances persist in the labor market, we see increasing evidence on both fronts that give officials more leeway to wait for restrictive policy to work.

As of now, and despite the constant reminders from Fed officials that more hikes are possible, we suspect that the FOMC is done tightening monetary policy (i.e., a terminal target range of 5.25 to 5.50 percent). However, while this represents a shift in our Fed call, it is not a material one. We still project policymakers holding the federal funds rate at the terminal rate well into 2024-Q2 to ensure that inflation is convincingly on a path back toward 2%. As inflation decelerates further and the economy struggles amid still-tight financial conditions, we expect the FOMC to begin its slow transition to easier policy. That said, rather than projecting a first cut of 25 basis points to come at the April 30/May 1 FOMC meeting, we now look for the change to occur at the June 11-12 gathering. We then look for the Committee to continue easing by 25-basis-point increments at each of the final four meetings of 2024, leading to a year-end target range of 4.00 to 4.25 percent (consistent with our previous forecast).

Messaging is likely to present a key challenge for officials in coming months despite what we view as a sufficiently restrictive monetary policy. Financial conditions are the primary transmission mechanism of monetary policy to the real economy, and while the economy has responded to tight financial conditions, maintenance of the current constraints on economic activity is essential to achieve desired policy outcomes, i.e., stable prices and maximum sustainable employment. Evidence of the challenge awaiting officials emerged as markets repriced to incorporate evolving expectations for monetary policy. The S&P 500 has rallied more than nine percent since its recent low on October 27, erasing much of the easing in the August-to-October period. Moreover, softening data and the perception that the Fed is done hiking interest rates contributed to a 16-basis-point drop in the 2-year yield from last Friday's close to 4.90 percent and a plunge of 21 basis points in the 10-year yield to 4.44 percent. Consequently, additional easing in financial conditions, despite the maintenance of restrictive policy, could jeopardize further progress toward policy objectives.

A near-term catalyst for movements in financial markets, and key contributory factor in the revision of our Fed call, was data this week that pointed more decidedly toward progress in inflation and easing in tight labor market conditions. On the inflation front, the CPI for October printed below expectations. The headline was flat while the core increased 0.2%. Moreover, risks tilted to the upside as many analysts were concerned that changes to the calculation of health insurance costs in the October report could lead to an upswing in a previously subdued area.

Headline CPI inflation has fallen from a peak of 9.1% in June 2022 to 3.2% in Oct, including a slowing of five ticks in the past month. Energy costs have dropped and increases in food prices have decelerated sharply. Improvement in the core component has been measurable, but less dramatic, as prices rose 4.0% in Oct vs 4.2% in Sep. Additionally, Fed officials rightly view core inflation as still well above the two percent target. Core goods inflation has returned to the pre-2020 trend after the unwinding of pandemic-related supply-demand imbalances (year-over-year growth of 0.1 percent as of October), but more improvement is required in core services where year-over-year growth has slowed from a peak of 7.3 percent in February 2023 but is still elevated at 5.5 percent. Housing costs (illustrated by owners' equivalent rent in the chart) is still a key contributor to core service costs and is widely expected to moderate only over time.

A helpful illustration of near-term progress on inflation is the recent month-to-month performance of the trimmed-mean CPI. (We view this measure as offering a better perspective of underlying inflation as it eliminates price changes at the tails of the monthly distribution.) On a year-over-year basis, this measure has remained elevated (growth of 4.1 percent versus 4.3 percent in September), but the far better near-term performance indicates a more forceful easing in underlying inflation (increases of 0.2 percent in five of the past eight months).

Data on unemployment claims also suggest a slowdown in the real economy that should further dull the underlying inflation impulse, while also emphasizing that risks to the outlook have become more two-sided. That is, the risks of doing too little to combat entrenched inflation must now be weighed against the risks of overtightening and doing unnecessary damage to the economy. While initial claims increased by 13,000 to 231,000 in the week of Nov 11, a reading above the pre-pandemic average of 218,000, which suggested a labor market on firm footing, they were still relatively low from a longer-term perspective. More important, and perhaps somewhat concerning, was the jump of 32,000 in continuing unemployment claims to 1.865 million in the week of Nov 4. Over the past eight weeks, continuing claims have risen by a cumulative 207,000 to the highest level in almost two years. On one hand, this development speaks to an ongoing rebalancing in a tight labor market; on the other hand, it may be the beginning of an uptrend that usually presents prior to the onset of a recession. Again, this development speaks to postponing further hikes, both because policy goals appear more attainable with the current level of monetary restraint and because caution is warranted as the economy possibly nears an inflection point.

Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2025 through 2029 and averages for the five-year periods 2025-2029 and 2030-2034. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		Average For The Year					Five-Year Averages	
		2025	2026	2027	2028	2029	2025-2029	2030-2034
1. Federal Funds Rate	CONSENSUS	**3.8**	**3.2**	**3.1**	**3.0**	**3.0**	**3.2**	**3.0**
	Top 10 Average	4.3	3.6	3.6	3.5	3.5	3.7	3.5
	Bottom 10 Average	3.3	2.7	2.6	2.6	2.5	2.7	2.5
2. Prime Rate	CONSENSUS	**6.9**	**6.3**	**6.2**	**6.2**	**6.2**	**6.3**	**6.1**
	Top 10 Average	7.3	6.7	6.7	6.6	6.6	6.8	6.6
	Bottom 10 Average	6.5	5.9	5.7	5.7	5.7	5.9	5.6
3. SOFR	CONSENSUS	**3.8**	**3.2**	**3.1**	**3.1**	**3.1**	**3.3**	**3.0**
	Top 10 Average	4.1	3.6	3.5	3.5	3.4	3.6	3.4
	Bottom 10 Average	3.4	2.9	2.7	2.7	2.6	2.9	2.6
4. Commercial Paper, 1-Mo	CONSENSUS	**3.7**	**3.2**	**3.2**	**3.2**	**3.1**	**3.3**	**3.1**
	Top 10 Average	3.9	3.5	3.4	3.4	3.4	3.5	3.4
	Bottom 10 Average	3.5	2.9	2.8	2.8	2.8	3.0	2.7
5. Treasury Bill Yield, 3-Mo	CONSENSUS	**3.7**	**3.2**	**3.1**	**3.0**	**3.0**	**3.2**	**3.0**
	Top 10 Average	4.1	3.6	3.6	3.5	3.5	3.7	3.5
	Bottom 10 Average	3.2	2.7	2.6	2.5	2.5	2.7	2.4
6. Treasury Bill Yield, 6-Mo	CONSENSUS	**3.7**	**3.3**	**3.2**	**3.2**	**3.1**	**3.3**	**3.1**
	Top 10 Average	4.1	3.7	3.6	3.6	3.6	3.7	3.6
	Bottom 10 Average	3.4	2.9	2.8	2.7	2.7	2.9	2.7
7. Treasury Bill Yield, 1-Yr	CONSENSUS	**3.7**	**3.4**	**3.3**	**3.3**	**3.2**	**3.4**	**3.2**
	Top 10 Average	4.1	3.8	3.7	3.7	3.7	3.8	3.7
	Bottom 10 Average	3.3	3.0	2.9	2.8	2.8	3.0	2.8
8. Treasury Note Yield, 2-Yr	CONSENSUS	**3.7**	**3.5**	**3.4**	**3.4**	**3.4**	**3.5**	**3.4**
	Top 10 Average	4.1	3.9	3.9	3.9	3.9	3.9	3.9
	Bottom 10 Average	3.3	3.1	3.0	2.9	2.9	3.0	2.9
9. Treasury Note Yield, 5-Yr	CONSENSUS	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**
	Top 10 Average	4.1	4.1	4.2	4.2	4.3	4.2	4.3
	Bottom 10 Average	3.3	3.2	3.2	3.1	3.1	3.2	3.1
10. Treasury Note Yield, 10-Yr	CONSENSUS	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**
	Top 10 Average	4.3	4.4	4.5	4.5	4.5	4.4	4.5
	Bottom 10 Average	3.5	3.3	3.3	3.3	3.3	3.3	3.3
11. Treasury Bond Yield, 30-Yr	CONSENSUS	**4.1**	**4.1**	**4.1**	**4.2**	**4.2**	**4.1**	**4.2**
	Top 10 Average	4.5	4.6	4.7	4.7	4.7	4.6	4.8
	Bottom 10 Average	3.8	3.6	3.6	3.6	3.6	3.7	3.6
12. Corporate Aaa Bond Yield	CONSENSUS	**5.0**	**4.9**	**4.9**	**5.0**	**5.0**	**4.9**	**5.0**
	Top 10 Average	5.3	5.3	5.4	5.5	5.5	5.4	5.5
	Bottom 10 Average	4.6	4.5	4.5	4.5	4.5	4.5	4.4
13. Corporate Baa Bond Yield	CONSENSUS	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**
	Top 10 Average	6.4	6.4	6.5	6.6	6.6	6.5	6.6
	Bottom 10 Average	5.7	5.5	5.5	5.6	5.6	5.6	5.6
14. State & Local Bonds Yield	CONSENSUS	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**
	Top 10 Average	4.6	4.7	4.7	4.8	4.8	4.7	4.9
	Bottom 10 Average	4.0	3.8	3.9	3.9	3.8	3.9	3.8
15. Home Mortgage Rate	CONSENSUS	**6.2**	**5.9**	**5.9**	**5.9**	**5.9**	**5.9**	**5.8**
	Top 10 Average	6.6	6.4	6.4	6.5	6.5	6.5	6.5
	Bottom 10 Average	5.7	5.5	5.4	5.3	5.2	5.4	5.2
A. Fed's AFE Nominal $ Index	CONSENSUS	**114.1**	**113.0**	**113.1**	**113.2**	**112.8**	**113.2**	**112.3**
	Top 10 Average	116.0	115.5	115.9	116.5	116.2	116.0	115.7
	Bottom 10 Average	111.8	110.4	110.1	109.6	109.1	110.2	108.5

		Year-Over-Year, % Change					Five-Year Averages	
		2025	2026	2027	2028	2029	2025-2029	2030-2034
B. Real GDP	CONSENSUS	**1.6**	**2.1**	**2.1**	**2.0**	**2.0**	**1.9**	**2.0**
	Top 10 Average	2.1	2.4	2.4	2.3	2.3	2.3	2.3
	Bottom 10 Average	1.1	1.8	1.8	1.7	1.7	1.6	1.7
C. GDP Chained Price Index	CONSENSUS	**2.2**	**2.2**	**2.1**	**2.1**	**2.2**	**2.2**	**2.2**
	Top 10 Average	2.5	2.3	2.3	2.3	2.3	2.3	2.3
	Bottom 10 Average	2.0	2.0	2.0	2.0	2.0	2.0	2.0
D. Consumer Price Index	CONSENSUS	**2.3**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**
	Top 10 Average	2.5	2.4	2.4	2.4	2.4	2.4	2.4
	Bottom 10 Average	2.1	2.1	2.0	2.0	2.0	2.0	2.0
E. PCE Price Index	CONSENSUS	**2.2**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**
	Top 10 Average	2.3	2.3	2.2	2.2	2.2	2.2	2.3
	Bottom 10 Average	2.0	2.0	1.9	1.9	2.0	1.9	2.0

Databank:

2023 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	2.8	-0.7	-0.9	0.4	0.7	0.2	0.6	0.7	0.9	-0.1	....	....
Auto & Light Truck Sales (b)	15.10	14.88	14.93	15.68	15.51	16.06	15.94	15.27	15.68	15.50	....	....
Personal Income (a, current $)	1.0	0.5	0.5	0.2	0.3	0.2	0.3	0.5	0.4	0.2	....	....
Personal Consumption (a, current $)	1.6	0.4	-0.1	0.4	0.2	0.4	0.7	0.4	0.7	0.2	....	....
Consumer Credit (e)	5.1	2.8	4.8	3.3	-0.2	3.1	2.7	-3.8	2.2	....	....	....
Consumer Sentiment (U. of Mich.)	64.9	66.9	62.0	63.7	59.0	64.2	71.5	69.4	67.9	63.8	61.3	....
Household Employment (c)	894	177	577	139	-310	273	268	222	86	-348	....	....
Nonfarm Payroll Employment (c)	472	248	217	217	281	105	236	165	297	150	....	....
Unemployment Rate (%)	3.4	3.6	3.5	3.4	3.7	3.6	3.5	3.8	3.8	3.9	....	....
Average Hourly Earnings (All, cur. $)	33.02	33.11	33.20	33.34	33.45	33.60	33.73	33.82	33.93	34.00	....	....
Average Workweek (All, hrs.)	34.6	34.5	34.4	34.4	34.3	34.4	34.3	34.4	34.4	34.3	....	....
Industrial Production (d)	1.5	0.9	0.2	0.3	0.1	-0.4	0.1	0.1	-0.2	-0.7	....	....
Capacity Utilization (%)	79.6	79.5	79.5	79.8	79.5	78.9	79.6	79.5	79.5	78.9	....	....
ISM Manufacturing Index (g)	47.4	47.7	46.3	47.1	46.9	46.0	46.4	47.6	49.0	46.7	....	....
ISM Nonmanufacturing Index (g)	55.2	55.1	51.2	51.9	50.3	53.9	52.7	54.5	53.6	51.8	....	....
Housing Starts (b)	1.340	1.436	1.380	1.348	1.583	1.418	1.451	1.305	1.346	1.372	....	....
Housing Permits (b)	1.354	1.482	1.437	1.417	1.496	1.441	1.443	1.541	1.471	1.498	....	....
New Home Sales (1-family, c)	649	625	640	679	710	683	728	662	719	679	....	....
Construction Expenditures (a)	2.2	0.4	0.6	0.3	2.0	0.5	0.7	1.0	0.4	....	....	....
Consumer Price Index (nsa, d)	6.4	6.0	5.0	4.9	4.0	3.0	3.2	3.7	3.7	3.2	....	....
CPI ex. Food and Energy (nsa, d)	5.6	5.5	5.6	5.5	5.3	4.8	4.7	4.3	4.1	4.0	....	....
PCE Chain Price Index (d)	5.5	5.2	4.4	4.4	4.0	3.2	3.4	3.4	3.4	3.0	....	....
Core PCE Chain Price Index (d)	4.9	4.8	4.8	4.8	4.7	4.3	4.3	3.8	3.7	3.5	....	....
Producer Price Index (nsa, d)	5.7	4.7	2.7	2.3	1.1	0.3	1.2	2.1	2.2	1.3	....	....
Durable Goods Orders (a)	-1.3	-2.7	3.3	1.2	2.0	4.3	-5.6	-0.1	4.0	-5.4	....	....
Leading Economic Indicators (a)	-0.5	-0.5	-1.2	-0.8	-0.7	-0.7	-0.2	-0.4	-0.7	-0.8	....	....
Balance of Trade & Services (f)	-70.8	-70.6	-60.4	-73.0	-66.8	-63.7	-64.7	-58.7	-61.5	....	....	....
Federal Funds Rate (%)	4.33	4.57	4.65	4.83	5.06	5.08	5.12	5.33	5.33	5.33	....	....
3-Mo. Treasury Bill Rate (%)	4.69	4.79	4.86	5.07	5.31	5.42	5.49	5.56	5.56	5.60	....	....
10-Year Treasury Note Yield (%)	3.53	3.75	3.66	3.46	3.57	3.75	3.90	4.17	4.38	4.80	....	....

2022 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	1.4	1.4	2.1	1.3	-0.1	0.8	-0.7	0.7	-0.3	1.4	-1.4	-0.7
Auto & Light Truck Sales (b)	14.38	13.67	13.58	14.04	12.94	13.27	13.49	13.50	13.70	14.68	14.27	13.55
Personal Income (a, current $)	-0.3	0.6	0.4	0.3	0.4	0.4	0.8	0.5	0.4	0.5	0.1	0.2
Personal Consumption (a, current $)	0.5	0.7	1.2	0.6	0.4	1.0	0.0	0.8	0.6	0.6	-0.1	0.3
Consumer Credit (e)	4.6	8.3	10.1	7.3	6.9	8.6	6.8	7.0	6.9	8.8	8.1	4.8
Consumer Sentiment (U. of Mich.)	67.2	62.8	59.4	65.2	58.4	50.0	51.5	58.2	58.6	59.9	56.7	59.8
Household Employment (c)	1041	468	738	-346	317	-242	215	422	156	-257	-66	717
Nonfarm Payroll Employment (c)	364	904	414	254	364	370	568	352	350	324	290	239
Unemployment Rate (%)	4.0	3.8	3.6	3.6	3.6	3.6	3.5	3.7	3.5	3.7	3.6	3.5
Average Hourly Earnings (All, cur. $)	31.63	31.63	31.83	31.94	32.06	32.18	32.33	32.43	32.53	32.66	32.80	32.92
Average Workweek (All, hrs.)	34.6	34.7	34.7	34.6	34.6	34.6	34.6	34.5	34.6	34.6	34.5	34.4
Industrial Production (d)	2.3	6.6	4.4	4.6	3.7	3.2	3.0	3.1	4.5	3.1	1.9	0.6
Capacity Utilization (%)	79.4	79.9	80.5	80.7	80.6	80.5	80.7	80.7	80.8	80.6	80.3	78.9
ISM Manufacturing Index (g)	57.6	58.4	57.0	55.9	56.1	53.1	52.7	52.9	51.0	50.0	49.0	48.4
ISM Nonmanufacturing Index (g)	60.4	57.2	58.4	57.5	56.4	56.0	56.4	56.1	55.9	54.5	55.5	49.2
Housing Starts (b)	1.669	1.771	1.713	1.803	1.543	1.561	1.371	1.505	1.463	1.432	1.427	1.357
Housing Permits (b)	1.898	1.817	1.877	1.795	1.708	1.701	1.658	1.586	1.588	1.555	1.402	1.409
New Home Sales (1-family, c)	810	773	707	611	636	563	543	638	567	577	582	636
Construction Expenditures (a)	2.4	1.5	1.4	1.8	-0.1	-0.4	-0.2	-1.2	-0.6	-0.4	0.6	-0.1
Consumer Price Index (nsa, d)	7.5	7.9	8.5	8.3	8.6	9.1	8.5	8.3	8.2	7.7	7.1	6.5
CPI ex. Food and Energy (nsa, d)	6.0	6.4	6.5	6.2	6.0	5.9	5.9	6.3	6.6	6.3	6.0	5.7
PCE Chain Price Index (d)	6.3	6.5	6.9	6.6	6.7	7.1	6.6	6.5	6.6	6.3	5.9	5.4
Core PCE Chain Price Index (d)	5.4	5.6	5.5	5.3	5.1	5.2	5.0	5.2	5.5	5.3	5.1	4.9
Producer Price Index (nsa, d)	10.1	10.4	11.7	11.2	11.1	11.2	9.7	8.7	8.5	8.2	7.4	6.4
Durable Goods Orders (a)	2.0	-1.4	-0.1	1.0	0.7	1.6	-0.8	-0.1	0.3	1.0	-3.1	4.5
Leading Economic Indicators (a)	-0.5	0.3	0.0	-0.6	-0.9	-0.7	-0.6	-0.3	-0.5	-0.9	-0.9	-0.7
Balance of Trade & Services (f)	-86.5	-87.0	-102.5	-86.0	-84.1	-80.9	-71.7	-67.3	-71.7	-78.3	-63.8	-71.4
Federal Funds Rate (%)	0.08	0.08	0.20	0.33	0.77	1.21	1.68	2.33	2.56	3.08	3.78	4.10
3-Mo. Treasury Bill Rate (%)	0.15	0.31	0.45	0.76	0.99	1.54	2.30	2.72	3.22	3.87	4.32	4.36
10-Year Treasury Note Yield (%)	1.76	1.93	2.13	2.75	2.90	3.14	2.90	2.90	3.52	3.98	3.89	3.62

(a) month-over-month % change; (b) millions, saar; (c) month-over-month change, thousands; (d) year-over-year % change; (e) annualized % change; (f) $ billions; (g) level. Most series are subject to frequent government revisions. Use with care.

Calendar of Upcoming Economic Data Releases

Monday	Tuesday	Wednesday	Thursday	Friday
December 4 Manufacturers' Shipments, Inventories & Orders (Oct) BEA Auto Sales (Nov) BEA Truck Sales (Nov) NABE Outlook (Q4)	**5** JOLTS (Oct) ISM Services PMI (Nov) S&P Global Services PMI (Nov)	**6** ADP Employment Report (Nov) Productivity & Costs (Q3) Intl Trade (Oct) Transportation Services Index (Oct) QFR (Q3) Public Debt (Nov) Interest on Public Debt (Nov) EIA Crude Oil Stocks Mortgage Applications	**7** Wholesale Trade (Oct) Treasury Auction Allotments (Nov) Consumer Credit (Oct) Financial Accounts (Q3) Challenger Employment Report (Nov) Weekly Jobless Claims	**8** Employment Situation (Nov) Consumer Sentiment (Dec, Preliminary)
11 Kansas City Financial Stress Index (Nov)	**12** CPI & Real Earnings (Nov) QSS (Q3) Cleveland Fed Median CPI(Nov) Monthly Treasury Statement (Nov) Manpower Survey (Q1) NFIB (Nov) Kansas City Fed Labor Market Conditions Indicators (Nov) FOMC Meeting	**13** Producer Prices (Nov) FOMC Meeting OPEC Crude Oil Spot Prices (Nov) EIA Crude Oil Stocks Mortgage Applications	**14** Advance Retail Sales (Nov) Import & Export Prices (Nov) MTIS (Oct) Weekly Jobless Claims	**15** IP & Capacity Utilization (Nov) ECEC (Q3) Empire State Mfg Survey (Dec) Livingston Survey (Apr) Housing Affordability (Oct)
18 Business Leaders Survey (Dec) Home Builders (Dec)	**19** New Residential Construction (Nov) TIC Data (Oct)	**20** International Transactions (Q3) Existing Home Sales (Nov) Consumer Confidence (Dec) EIA Crude Oil Stocks Mortgage Applications	**21** GDP & Corp Profits (Q3, 3rd Estimate) Philadelphia Fed Mfg Business Outlook Survey (Dec) Kansas City Fed Manufacturing Survey (Dec) Composite Indexes (Nov) Weekly Jobless Claims	**22** Personal Income (Nov) Underlying NIPA Tables (Q3, 3rd Estimate) Advance Durable Goods (Nov) New Residential Sales (Nov) Building Permits (Nov) Consumer Sentiment(Dec, Final) Dallas Fed Trim-Mean PCE (Nov) Treas Auction Allotments (Dec) S&P Global Flash PMIs (Dec)
25 **CHRISTMAS DAY** **ALL MARKETS CLOSED**	**26** FHFA HPI (Oct) Case-Shiller HPI (Oct) H.6 Money Stock (Nov) Philadelphia Fed Nonmfg Business Outlook (Dec) Chicago Fed National Activity Index (Nov) Texas Mfg Outlook (Dec)	**27** Richmond Fed Mfg & Service Sector Surveys (Dec) Texas Service Sector Outlook Survey (Dec) Mortgage Applications	**28** Adv Trade & Inventories (Nov) Intl Investment Position (Q3) Steel Imports for Consumption (Nov, Preliminary) Pending Home Sales (Nov) EIA Crude Oil Stocks Weekly Jobless Claims	**29** Agricultural Prices (Nov) Strike Report (Dec) Chicago PMI (Dec) FRB Philadelphia Coincident Economic Activity Index (Nov)
January 1 **NEW YEAR'S DAY** **ALL MARKETS CLOSED**	**2** Construction (Nov) Dallas Fed Banking Conditions Survey (Nov) S&P Global Mfg PMI (Dec)	**3** ISM Manufacturing (Dec) JOLTS (Nov) Mortgage Applications	**4** ADP Employment Report (Dec) Challenger Employment Report (Dec)| S&P Global Services PMI (Dec) BEA Auto & Truck Sales (Dec) EIA Crude Oil Stocks Weekly Jobless Claims	**5** Employment Situation (Dec) MSIO (Nov) Public Debt (Dec) Interest Expense on Public Debt (Dec) ISM Services PMI (Dec)
8 Consumer Credit (Nov)	**9** International Trade (Nov) NFIB (Dec) Kansas City Financial Stress Index (Dec)	**10** Wholesale Trade (Nov) EIA Crude Oil Stocks Mortgage Applications	**11** CPI & Real Earnings (Dec) Cleveland Fed Median CPI(Dec) Monthly Treasury Statement (Dec) Weekly Jobless Claims	**12** Producer Prices (Dec)

BLUE CHIP FORECASTERS

CONTRIBUTORS TO DOMESTIC SURVEY

Action Economics, LLC, Boulder, CO
Michael Englund

Amherst Pierpont Securities, Stamford, CT
Stephen Stanley

Bank of America, New York, NY
Ethan Harris

Barclays, New York, NY
Marc Giannoni

BMO Capital Markets Economics, Toronto, Canada
Scott Anderson

BNP Paribas North America, New York, NY
Andrew Schneider

Chan Economics, New York, NY
Anthony Chan

Chmura Economics & Analytics, Richmond, VA
Christine Chmura and Xiaobing Shuai

Comerica, Dallas, TX
Bill Adams

Daiwa Capital Markets America, New York, NY
Michael Moran

DePrince & Associates, Murfreesburo, TN
Albert E. DePrince Jr.

Economist Intelligence Unit, New York, NY
Leo Abruzzese and Jan Friederich

EY- Parthenon, New York, NY
Gregory Daco

Fannie Mae, Washington, DC
Douglas Duncan

Georgia State University, Atlanta, GA
Rajeev Dhawan

GLC Financial Economics, Providence, RI
Gary L. Ciminero

Goldman, Sachs & Co., New York, NY
Jan Hatzius

KPMG, New York, NY
Diane Swonk

ING Financial Markets, London, England
James Knightley

J.P. Morgan Chase, New York, NY
Bruce Kasman

Loomis, Sayles & Company, L.P., Boston, MA
Brian Horrigan

MacroFin Analytics & Rutgers Business School, Wayne, NJ
Parul Jain

MacroPolicy Perspectives, New York, NY
Julia Coronado and Laura Rosner

Moody's Analytics, West Chester, PA
Mark M. Zandi

Naroff Economic Advisors, Philadelphia, PA
Joel L. Naroff

Nationwide, New York, NY
Kathy Bostjancic

NatWest Markets, Greenwich, CT
Kevin Cummins and Deepika Dayal

Nomura Securities International, Inc., New York, NY
U.S. Economics

Northern Trust Company, Chicago, IL
Carl Tannenbaum

Oxford Economics, New York, NY
Oren Klachkin

PNC Financial Services Group, Pittsburgh, PA
Gus Faucher

RDQ Economics, New York, NY
John Ryding and Conrad de Quadros

Regions Financial Corporation, Birmingham, AL
Richard F. Moody

Scotiabank Group, Toronto, Canada
Jean-Francois Perrault

Societe Generale, New York, NY
Stephen W. Gallagher

S&P Global Market Intelligence, St. Louis, MO
Joel Prakken & Chris Varvares

Swiss Re, New York, NY
Jerome Haegeli

The Lonski Group, White Plains, NY
John Lonski

TS Lombard, London, UK
Steven Blitz

Via Nova Investment Management, Crozet, VA
Alan Gayle

Wells Fargo, Charlotte, NC
Jay Bryson

CONTRIBUTORS TO INTERNATIONAL SURVEY

Barclays Capital, New York, NY
BMO Capital Markets Economics, Toronto, Canada
ING Financial Markets, London, England
Moody's Analytics, West Chester, PA
Nomura Securities International, Inc., New York, NY
Northern Trust Company, Chicago, IL
Oxford Economics, Wayne, PA
Scotiabank Group, Toronto, Canada
S&P Global Market Intelligence, St. Louis, MO
TS Lombard, London, UK
Wells Fargo, Charlotte, NC

U.S. Capital Markets Performance
by Asset Class 1926–2022

2023
SBBI® Yearbook

STOCKS, BONDS, BILLS, AND INFLATION®

Roger G. Ibbotson

Appendix A-1

Large-Capitalization Stocks: Total Return
From 1926 to 2022

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Jan-Dec*
1926	0.0000	-0.0385	-0.0575	0.0253	0.0179	0.0457	0.0479	0.0248	0.0252	-0.0284	0.0347	0.0196	1926	0.1162
1927	-0.0193	0.0537	0.0087	0.0201	0.0607	-0.0067	0.0670	0.0515	0.0450	-0.0502	0.0721	0.0279	1927	0.3749
1928	-0.0040	-0.0125	0.1101	0.0345	0.0197	-0.0385	0.0141	0.0803	0.0259	0.0168	0.1292	0.0049	1928	0.4361
1929	0.0583	-0.0019	-0.0012	0.0176	-0.0362	0.1140	0.0471	0.1028	-0.0476	-0.1973	-0.1246	0.0282	1929	-0.0842
1930	0.0639	0.0259	0.0812	-0.0080	-0.0096	-0.1625	0.0386	0.0141	-0.1282	-0.0855	-0.0089	-0.0706	1930	-0.2490
1931	0.0502	0.1193	-0.0675	-0.0935	-0.1279	0.1421	-0.0722	0.0182	-0.2973	0.0896	-0.0798	-0.1400	1931	-0.4334
1932	-0.0271	0.0570	-0.1158	-0.1997	-0.2196	-0.0022	0.3815	0.3869	-0.0346	-0.1349	-0.0417	0.0565	1932	-0.0819
1933	0.0087	-0.1772	0.0353	0.4256	0.1683	0.1338	-0.0862	0.1206	-0.1118	-0.0855	0.1127	0.0253	1933	0.5399
1934	0.1069	-0.0322	0.0000	-0.0251	-0.0736	0.0229	-0.1132	0.0611	-0.0033	-0.0286	0.0942	-0.0010	1934	-0.0144
1935	-0.0411	-0.0341	-0.0286	0.0980	0.0409	0.0699	0.0850	0.0280	0.0256	0.0777	0.0474	0.0394	1935	0.4767
1936	0.0670	0.0224	0.0268	-0.0751	0.0545	0.0333	0.0701	0.0151	0.0031	0.0775	0.0134	-0.0029	1936	0.3392
1937	0.0390	0.0191	-0.0077	-0.0809	-0.0024	-0.0504	0.1045	-0.0483	-0.1403	-0.0981	-0.0866	-0.0459	1937	-0.3503
1938	0.0152	0.0674	-0.2487	0.1447	-0.0330	0.2503	0.0744	-0.0226	0.0166	0.0776	-0.0273	0.0401	1938	0.3112
1939	-0.0674	0.0390	-0.1339	-0.0027	0.0733	-0.0612	0.1105	-0.0648	0.1673	-0.0123	-0.0398	0.0270	1939	-0.0041
1940	-0.0336	0.0133	0.0124	-0.0024	-0.2289	0.0809	0.0341	0.0350	0.0123	0.0422	-0.0316	0.0009	1940	-0.0978
1941	-0.0463	-0.0060	0.0071	-0.0612	0.0183	0.0578	0.0579	0.0010	-0.0068	-0.0657	-0.0284	-0.0407	1941	-0.1159
1942	0.0161	-0.0159	-0.0652	-0.0400	0.0796	0.0221	0.0337	0.0164	0.0290	0.0678	-0.0021	0.0549	1942	0.2034
1943	0.0737	0.0583	0.0545	0.0035	0.0552	0.0223	-0.0526	0.0171	0.0263	-0.0108	-0.0654	0.0617	1943	0.2590
1944	0.0171	0.0042	0.0195	-0.0100	0.0505	0.0543	-0.0193	0.0157	-0.0008	0.0023	0.0133	0.0374	1944	0.1975
1945	0.0158	0.0683	-0.0441	0.0902	0.0195	-0.0007	-0.0180	0.0641	0.0438	0.0322	0.0396	0.0116	1945	0.3644
1946	0.0714	-0.0641	0.0480	0.0393	0.0288	-0.0370	-0.0239	-0.0674	-0.0997	-0.0060	-0.0027	0.0457	1946	-0.0807
1947	0.0255	-0.0077	-0.0149	-0.0363	0.0014	0.0554	0.0381	-0.0203	-0.0111	0.0238	-0.0175	0.0233	1947	0.0571
1948	-0.0379	-0.0388	0.0793	0.0292	0.0879	0.0054	-0.0508	0.0158	-0.0276	0.0710	-0.0961	0.0346	1948	0.0550
1949	0.0039	-0.0296	0.0328	-0.0179	-0.0258	0.0014	0.0650	0.0219	0.0263	0.0340	0.0175	0.0486	1949	0.1879
1950	0.0197	0.0199	0.0070	0.0486	0.0509	-0.0548	0.0119	0.0443	0.0592	0.0093	0.0169	0.0513	1950	0.3171
1951	0.0637	0.0157	-0.0156	0.0509	-0.0299	-0.0228	0.0711	0.0478	0.0013	-0.0103	0.0096	0.0424	1951	0.2402
1952	0.0181	-0.0282	0.0503	-0.0402	0.0343	0.0490	0.0196	-0.0071	-0.0176	0.0020	0.0571	0.0382	1952	0.1837
1953	-0.0049	-0.0106	-0.0212	-0.0237	0.0077	-0.0134	0.0273	-0.0501	0.0034	0.0540	0.0204	0.0053	1953	-0.0099
1954	0.0536	0.0111	0.0325	0.0516	0.0418	0.0031	0.0589	-0.0275	0.0851	-0.0167	0.0909	0.0534	1954	0.5262
1955	0.0197	0.0098	-0.0030	0.0396	0.0055	0.0841	0.0622	-0.0025	0.0130	-0.0284	0.0827	0.0015	1955	0.3156
1956	-0.0347	0.0413	0.0710	-0.0004	-0.0593	0.0409	0.0530	-0.0328	-0.0440	0.0066	-0.0050	0.0370	1956	0.0656
1957	-0.0401	-0.0264	0.0215	0.0388	0.0437	0.0004	0.0131	-0.0505	-0.0602	-0.0302	0.0231	-0.0395	1957	-0.1078

Appendix A-1

Large-Capitalization Stocks: Total Return
From 1926 to 2022

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Jan–Dec*
1958	0.0445	-0.0141	0.0328	0.0337	0.0212	0.0279	0.0449	0.0176	0.0501	0.0270	0.0284	0.0535	1958	0.4336
1959	0.0053	0.0049	0.0020	0.0402	0.0240	-0.0022	0.0363	-0.0102	-0.0443	0.0128	0.0186	0.0292	1959	0.1196
1960	-0.0700	0.0147	-0.0123	-0.0161	0.0326	0.0211	-0.0234	0.0317	-0.0590	-0.0007	0.0465	0.0479	1960	0.0047
1961	0.0645	0.0319	0.0270	0.0051	0.0239	-0.0275	0.0342	0.0243	-0.0184	0.0298	0.0447	0.0046	1961	0.2689
1962	-0.0366	0.0209	-0.0046	-0.0607	-0.0811	-0.0803	0.0652	0.0208	-0.0465	0.0064	0.1086	0.0153	1962	-0.0873
1963	0.0506	-0.0239	0.0370	0.0500	0.0193	-0.0188	-0.0022	0.0535	-0.0097	0.0339	-0.0046	0.0262	1963	0.2280
1964	0.0283	0.0147	0.0165	0.0075	0.0162	0.0178	0.0195	-0.0118	0.0301	0.0096	0.0005	0.0056	1964	0.1648
1965	0.0345	0.0031	-0.0133	0.0356	-0.0030	-0.0473	0.0147	0.0272	0.0334	0.0289	-0.0031	0.0106	1965	0.1245
1966	0.0062	-0.0131	-0.0205	0.0220	-0.0492	-0.0146	-0.0120	-0.0725	-0.0053	0.0494	0.0095	0.0002	1966	-0.1006
1967	0.0798	0.0072	0.0409	0.0437	-0.0477	0.0190	0.0468	-0.0070	0.0342	-0.0276	0.0065	0.0278	1967	0.2398
1968	-0.0425	-0.0261	0.0110	0.0834	0.0161	0.0105	-0.0172	0.0164	0.0400	0.0087	0.0531	-0.0402	1968	0.1106
1969	-0.0068	-0.0426	0.0359	0.0229	0.0026	-0.0542	-0.0587	0.0454	-0.0236	0.0459	-0.0297	-0.0177	1969	-0.0850
1970	-0.0743	0.0558	0.0044	-0.0875	-0.0578	-0.0466	0.0769	0.0478	0.0362	-0.0083	0.0506	0.0597	1970	0.0386
1971	0.0432	0.0117	0.0394	0.0389	-0.0391	0.0033	-0.0387	0.0388	-0.0044	-0.0392	0.0002	0.0888	1971	0.1430
1972	0.0206	0.0277	0.0083	0.0068	0.0197	-0.0194	0.0048	0.0369	-0.0025	0.0118	0.0481	0.0142	1972	0.1900
1973	-0.0149	-0.0352	0.0008	-0.0383	-0.0163	-0.0040	0.0407	-0.0341	0.0427	0.0017	-0.1109	0.0198	1973	-0.1469
1974	-0.0072	-0.0007	-0.0205	-0.0359	-0.0302	-0.0113	-0.0742	-0.0864	-0.1152	0.1681	-0.0488	-0.0156	1974	-0.2647
1975	0.1272	0.0638	0.0254	0.0510	0.0477	0.0477	-0.0644	-0.0176	-0.0312	0.0653	0.0282	-0.0081	1975	0.3723
1976	0.1217	-0.0084	0.0337	-0.0078	-0.0111	0.0443	-0.0048	-0.0018	0.0258	-0.0186	-0.0041	0.0561	1976	0.2393
1977	-0.0473	-0.0182	-0.0105	0.0042	-0.0196	0.0494	-0.0124	-0.0172	0.0016	-0.0390	0.0316	0.0075	1977	-0.0716
1978	-0.0574	-0.0203	0.0294	0.0902	0.0092	-0.0138	0.0583	0.0301	-0.0032	-0.0872	0.0215	0.0196	1978	0.0657
1979	0.0443	-0.0321	0.0596	0.0063	-0.0217	0.0435	0.0134	0.0577	0.0043	-0.0640	0.0475	0.0214	1979	0.1861
1980	0.0622	-0.0001	-0.0972	0.0462	0.0515	0.0316	0.0696	0.0101	0.0294	0.0202	0.1065	-0.0302	1980	0.3250
1981	-0.0418	0.0174	0.0400	-0.0193	0.0026	-0.0063	0.0021	-0.0577	-0.0493	0.0540	0.0413	-0.0256	1981	-0.0492
1982	-0.0131	-0.0559	-0.0052	0.0452	-0.0341	-0.0150	-0.0178	0.1214	0.0125	0.1151	0.0404	0.0193	1982	0.2155
1983	0.0372	0.0229	0.0369	0.0788	-0.0087	0.0389	-0.0295	0.0150	0.0138	-0.0116	0.0211	-0.0052	1983	0.2256
1984	-0.0056	-0.0352	0.0173	0.0095	-0.0554	0.0217	-0.0124	0.1104	0.0002	0.0039	-0.0112	0.0263	1984	0.0627
1985	0.0779	0.0122	0.0007	-0.0009	0.0578	0.0157	-0.0015	-0.0085	-0.0313	0.0462	0.0686	0.0484	1985	0.3173
1986	0.0056	0.0747	0.0558	-0.0113	0.0532	0.0169	-0.0559	0.0742	-0.0827	0.0577	0.0243	-0.0255	1986	0.1867
1987	0.1347	0.0395	0.0289	-0.0089	0.0087	0.0505	0.0507	0.0373	-0.0219	-0.2154	-0.0824	0.0761	1987	0.0525
1988	0.0421	0.0466	-0.0309	0.0111	0.0086	0.0459	-0.0038	-0.0339	0.0426	0.0278	-0.0143	0.0174	1988	0.1661
1989	0.0732	-0.0249	0.0233	0.0519	0.0405	-0.0057	0.0903	0.0195	-0.0041	-0.0232	0.0204	0.0240	1989	0.3169

Appendix A-1

Large-Capitalization Stocks: Total Return
From 1926 to 2022

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Jan–Dec*
1990	-0.0671	0.0129	0.0265	-0.0249	0.0975	-0.0067	-0.0032	-0.0904	-0.0487	-0.0043	0.0646	0.0279	1990	-0.0310
1991	0.0436	0.0715	0.0242	0.0024	0.0431	-0.0458	0.0466	0.0237	-0.0167	0.0134	-0.0403	0.1144	1991	0.3047
1992	-0.0186	0.0130	-0.0194	0.0294	0.0049	-0.0149	0.0409	-0.0205	0.0118	0.0035	0.0341	0.0123	1992	0.0762
1993	0.0084	0.0136	0.0211	-0.0242	0.0268	0.0029	-0.0040	0.0379	-0.0077	0.0207	-0.0095	0.0121	1993	0.1008
1994	0.0340	-0.0271	-0.0436	0.0128	0.0164	-0.0245	0.0328	0.0410	-0.0245	0.0225	-0.0364	0.0148	1994	0.0132
1995	0.0259	0.0390	0.0295	0.0294	0.0400	0.0232	0.0332	0.0025	0.0422	-0.0036	0.0439	0.0193	1995	0.3758
1996	0.0340	0.0093	0.0096	0.0147	0.0258	0.0038	-0.0442	0.0211	0.0563	0.0276	0.0756	-0.0198	1996	0.2296
1997	0.0625	0.0078	-0.0411	0.0597	0.0609	0.0448	0.0796	-0.0560	0.0548	-0.0334	0.0463	0.0172	1997	0.3336
1998	0.0111	0.0721	0.0512	0.0101	-0.0172	0.0406	-0.0106	-0.1446	0.0641	0.0813	0.0606	0.0576	1998	0.2858
1999	0.0418	-0.0311	0.0400	0.0387	-0.0236	0.0555	-0.0312	-0.0049	-0.0274	0.0633	0.0203	0.0589	1999	0.2104
2000	-0.0502	-0.0189	0.0978	-0.0301	-0.0205	0.0247	-0.0156	0.0621	-0.0528	-0.0042	-0.0788	0.0049	2000	-0.0910
2001	0.0355	-0.0912	-0.0634	0.0777	0.0067	-0.0243	-0.0098	-0.0626	-0.0808	0.0191	0.0767	0.0088	2001	-0.1189
2002	-0.0146	-0.0193	0.0376	-0.0606	-0.0074	-0.0712	-0.0780	0.0066	-0.1087	0.0880	0.0589	-0.0587	2002	-0.2210
2003	-0.0262	-0.0150	0.0097	0.0824	0.0527	0.0128	0.0176	0.0195	-0.0106	0.0566	0.0088	0.0524	2003	0.2868
2004	0.0184	0.0139	-0.0151	-0.0157	0.0137	0.0194	-0.0331	0.0040	0.0108	0.0153	0.0405	0.0340	2004	0.1088
2005	-0.0244	0.0210	-0.0177	-0.0190	0.0318	0.0014	0.0372	-0.0091	0.0081	-0.0167	0.0378	0.0003	2005	0.0491
2006	0.0265	0.0027	0.0124	0.0134	-0.0288	0.0014	0.0062	0.0238	0.0258	0.0326	0.0190	0.0140	2006	0.1579
2007	0.0151	-0.0196	0.0112	0.0443	0.0349	-0.0166	-0.0310	0.0150	0.0374	0.0159	-0.0418	-0.0069	2007	0.0549
2008	-0.0600	-0.0325	-0.0043	0.0487	0.0130	-0.0843	-0.0084	0.0145	-0.0891	-0.1679	-0.0718	0.0106	2008	-0.3700
2009	-0.0843	-0.1065	0.0876	0.0957	0.0559	0.0020	0.0756	0.0361	0.0373	-0.0186	0.0600	0.0193	2009	0.2646
2010	-0.0360	0.0310	0.0603	0.0158	-0.0799	-0.0523	0.0701	-0.0451	0.0892	0.0380	0.0001	0.0668	2010	0.1506
2011	0.0237	0.0343	0.0004	0.0296	-0.0113	-0.0167	-0.0203	-0.0543	-0.0703	0.1093	-0.0022	0.0102	2011	0.0211
2012	0.0448	0.0432	0.0329	-0.0063	-0.0601	0.0412	0.0139	0.0225	0.0258	-0.0185	0.0058	0.0091	2012	0.1600
2013	0.0518	0.0136	0.0375	0.0193	0.0234	-0.0134	0.0509	-0.0290	0.0314	0.0460	0.0305	0.0253	2013	0.3239
2014	-0.0346	0.0457	0.0084	0.0074	0.0235	0.0207	-0.0138	0.0400	-0.0140	0.0244	0.0269	-0.0025	2014	0.1369
2015	-0.0300	0.0575	-0.0158	0.0096	0.0129	-0.0194	0.0210	-0.0603	-0.0247	0.0844	0.0030	-0.0158	2015	0.0138
2016	-0.0496	-0.0013	0.0678	0.0039	0.0180	0.0026	0.0369	0.0014	0.0002	-0.0182	0.0370	0.0198	2016	0.1196
2017	0.0190	0.0397	0.0012	0.0103	0.0141	0.0062	0.0206	0.0031	0.0206	0.0233	0.0307	0.0111	2017	0.2183
2018	0.0573	-0.0369	-0.0254	0.0038	0.0241	0.0062	0.0372	0.0326	0.0057	-0.0684	0.0204	-0.0903	2018	-0.0438
2019	0.0801	0.0321	0.0194	0.0405	-0.0635	0.0705	0.0144	-0.0158	0.0187	0.0217	0.0363	0.0302	2019	0.3149
2020	-0.0004	-0.0823	-0.1235	0.1282	0.0476	0.0199	0.0564	0.0719	-0.0380	-0.0266	0.1095	0.0384	2020	0.1840
2021	-0.0101	0.0276	0.0438	0.0534	0.0070	0.0233	0.0238	0.0304	-0.0465	0.0701	-0.0069	0.0448	2021	0.2871
2022	-0.0517	-0.0299	0.0371	-0.0872	0.0018	-0.0825	0.0922	-0.0408	-0.0921	0.0810	0.0559	-0.0576	2022	-0.1811

NEW REGULATORY FINANCE

Roger A. Morin, PhD

2006
PUBLIC UTILITIES REPORTS, INC.
Vienna, Virginia

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First Printing, June 2006

Library of Congress Cataloging-in-Publication Data
Morin, Roger A.
New regulatory finance/Roger A. Morin.
p. cm.
Rev. ed. of: Regulatory finance. 1994.
Includes bibliographical references and index.
ISBN-13: 978-0-910325-05-9
ISBN-10: 0-910325-05-7
1. Public utilities—United States—Finance. 2. Public utilities—Rate of return. 3. Public utilities—Law and legislation—United States. 4. Capital costs—United States. I. Morin, Roger A. Regulatory finance. II. Public Utilities Reports, Inc. III. Title.

HD2766.M62 2006
363.6068'1—dc22

2006018026

Printed in the United States of America

The model is analogous to the standard CAPM, but with the return on a minimum risk portfolio that is unrelated to market returns, R_Z, replacing the risk-free rate, R_F. The model has been empirically tested by Black, Jensen, and Scholes (1972), who find a flatter than predicted SML, consistent with the model and other researchers' findings. An updated version of the Black-Jensen-Scholes study is available in Brealey, Myers, and Allen (2006) and reaches similar conclusions.

The zero-beta CAPM cannot be literally employed to estimate the cost of capital, since the zero-beta portfolio is a statistical construct difficult to replicate. Attempts to estimate the model are formally equivalent to estimating the constants, a and b, in Equation 6-2. A practical alternative is to employ the Empirical CAPM, to which we now turn.

6.3 Empirical CAPM

As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical findings. The ECAPM estimates the cost of capital with the equation:

$$K = R_F + \acute{\alpha} + \beta \times (MRP - \acute{\alpha}) \qquad (6\text{-}5)$$

where $\acute{\alpha}$ is the "alpha" of the risk-return line, a constant, and the other symbols are defined as before. All the potential vagaries of the CAPM are telescoped into the constant $\acute{\alpha}$, which must be estimated econometrically from market data. Table 6-2 summarizes[10] the empirical evidence on the magnitude of alpha.[11]

[10] The technique is formally applied by Litzenberger, Ramaswamy, and Sosin (1980) to public utilities in order to rectify the CAPM's basic shortcomings. Not only do they summarize the criticisms of the CAPM insofar as they affect public utilities, but they also describe the econometric intricacies involved and the methods of circumventing the statistical problems. Essentially, the average monthly returns over a lengthy time period on a large cross-section of securities grouped into portfolios are related to their corresponding betas by statistical regression techniques; that is, Equation 6-5 is estimated from market data. The utility's beta value is substituted into the equation to produce the cost of equity figure. Their own results demonstrate how the standard CAPM underestimates the cost of equity capital of public utilities because of utilities' high dividend yield and return skewness.

[11] Adapted from Vilbert (2004).

TABLE 6-2
EMPIRICAL EVIDENCE ON THE ALPHA FACTOR

Author	Range of alpha
Fischer (1993)	−3.6% to 3.6%
Fischer, Jensen and Scholes (1972)	−9.61% to 12.24%
Fama and McBeth (1972)	4.08% to 9.36%
Fama and French (1992)	10.08% to 13.56%
Litzenberger and Ramaswamy (1979)	5.32% to 8.17%
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 5.04%
Pettengill, Sundaram and Mathur (1995)	4.6%
Morin (1989)	2.0%

For an alpha in the range of 1%–2% and for reasonable values of the market risk premium and the risk-free rate, Equation 6-5 reduces to the following more pragmatic form:

$$K = R_F + 0.25\ (R_M - R_F) + 0.75\ \beta(R_M - R_F) \qquad (6\text{-}6)$$

Over reasonable values of the risk-free rate and the market risk premium, Equation 6-6 produces results that are indistinguishable from the ECAPM of Equation 6-5.[12]

An alpha range of 1%–2% is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. That is, the

[12] Typical of the empirical evidence on the validity of the CAPM is a study by Morin (1989) who found that the relationship between the expected return on a security and beta over the period 1926–1984 was given by:

$$\text{Return} = 0.0829 + 0.0520\ \beta$$

Given that the risk-free rate over the estimation period was approximately 6% and that the market risk premium was 8% during the period of study, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2%, or 1/4 of 8%, and that the slope of the relationship is close to 3/4 of 8%. Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:

$$K = R_F + x(R_M - R_F) + (1 - x)\beta(R_M - R_F)$$

where x is a fraction to be determined empirically. The value of x that best explains the observed relationship Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:

$$K = R_F + 0.25(R_M - R_F) + 0.75\beta(R_M - R_F)$$

long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. Thus, it is reasonable to apply a conservative alpha adjustment. Moreover, the lowering of the tax burden on capital gains and dividend income enacted in 2002 may have decreased the required return for taxable investors, steepening the slope of the ECAPM risk-return trade-off and bring it closer to the CAPM predicted returns.[13]

To illustrate the application of the ECAPM, assume a risk-free rate of 5%, a market risk premium of 7%, and a beta of 0.80. The Empirical CAPM equation (6-6) above yields a cost of equity estimate of 11.0% as follows:

$$\begin{aligned} K &= 5\% + 0.25\,(12\% - 5\%) + 0.75 \times 0.80\,(12\% - 5\%) \\ &= 5.0\% + 1.8\% + 4.2\% \\ &= 11.0\% \end{aligned}$$

As an alternative to specifying alpha, see Example 6-1.

Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. Moreover, recall from Chapter 3 that the use of adjusted betas compensates for interest rate sensitivity of utility stocks not captured by unadjusted betas.

[13] The lowering of the tax burden on capital gains and dividend income has no impact as far as non-taxable institutional investors (pension funds, 401K, and mutual funds) are concerned, and such investors engage in very large amounts of trading on security markets. It is quite plausible that taxable retail investors are relatively inactive traders and that large non-taxable investors have a substantial influence on capital markets.

MANAGERIAL AND DECISION ECONOMICS
Manage. Decis. Econ **19**: 127–135 (1998)

Interest Rate Risk and Utility Risk Premia During 1982–93

S. Keith Berry*

Department of Economics and Business, Hendrix College, Conway, USA

INTRODUCTION

The risk premium method of calculating a fair return on equity for a regulated utility is frequently used in regulatory proceedings. That method considers the relationship between a utility's bond yield and its required return on equity, and is especially useful when other methods, such as the capital asset pricing model and the discounted cash flow (DCF) model exhibit less reliability.[1] Although the discounted cash flow method is the favored method for estimating a utility's cost of equity in rate proceedings, the risk premium method provides a useful check on the DCF results. This is even more important in today's financial environment because of the difficulty of measuring investor-expected growth rates in the DCF method.

If bond yields and required returns on equity move up and down in lockstep, it is straightforward to calculate the appropriate cost of equity using the risk premium method. However, if they do not, estimation of the cost of equity is much more difficult. One explanation of this variability in risk premia is differences in 'interest rate risk'. In particular, arguments have been made in rate cases that utility bonds are riskier in the 1980s than they were earlier because of the significant increase in interest rate variability that occurred in the early 1980s (primarily caused by increased inflation rate variability).[2] In particular, when capital costs, and interest rates, increase, utility bondholders, who earlier 'locked-in' at lower interest rates, miss out on those higher interest rates. Bondholders who experience this will then prospectively require an 'interest rate risk' premium, and utility bond interest rates will be correspondingly greater. Furthermore, utility bonds of differing overall risk may exhibit differing sensitivities to that 'interest rate risk'.

In contrast, the argument goes, utility common stock returns have some protection from that risk. If capital costs increase, utilities can request a rate increase to increase the allowed return. Consequently, utility common shareholders can earn the higher capital costs, and do not necessarily require an 'interest rate risk' premium.[3] Thus, over time we would not necessarily expect to see utility bond yields and required equity returns move in one-to-one lockstep. Furthermore, to the extent that there is some substitutability between utility common stocks and utility bonds as interest rate risk associated with bonds increases, investors may increase their preferences for utility stocks. This should tend to decrease required returns on utility common stock.

Berry (1995) performed an analysis of the impact of interest rate (and capital cost) risk on interest rates and dividend yields. Those results indicate that interest rates are positively related to interest rate variability, but dividend yields are not affected by dividend yield variability. However, that study focused on *dividend yields*, which are easy to measure, and did not consider required equity returns which are much more difficult to measure. Furthermore, that study did not focus on risk premia, and the relationship between bond yields and required returns on equity, as does this paper. This paper utilizes required returns, as measured by Commission-allowed returns, in the risk premium analysis.

* Correspondence to: Department of Economics and Business, Box 3180, Hendrix College, Conway, AR 72032, USA.

CCC 0143–6570/98/020127-09$17.50

Other studies have shown that there is an inverse relationship between interest rates and risk premia in recent years, but not in earlier years. Carleton *et al.* (1983) found that there was no relationship between electric utility risk premia and interest rates during the 1970s. Brigham *et al.* (1985) estimated a positive relationship between risk premia and interest rates for the 1966–79 period and a negative relationship between the variables during the 1980–84 period. They attributed this to increased inflation risk and its effect on interest rates. Similarly, Harris (1986) showed that there was a negative relationship between utility risk premia and interest rates during the 1982–84 period. Harris and Marston (1992) concluded that there was a negative relationship between the S&P 500 risk premia and interest rates for the 1982–91 period. However, none of these studies used Commission-allowed returns in the calculations of risk premia.

This paper considers two factors not previously considered in the literature. First, allowed returns are used as a proxy for required returns on equity, with appropriate consideration for partial adjustment. Second, explicit usage is made of measures of interest rate risk to gauge their impact on risk premia. Regression analyses is employed to estimate the effects of utility bond yields, interest rate variability, and time trends on required returns on equity and risk premia over the period 1982–93. In the second section, we present a simple regression model, which tests for an inverse relationship between required returns on equity and interest rates. This model, while not very sophisticated, has the inherent advantage that it can be easily used to estimate risk premia. In the third section, we consider a more complex model which explicitly considers various measures of interest rate variability, as well as interest rate levels.

REGRESSION RESULTS WITH INTEREST RATES

A common formulation of the risk premium is:

$$K = YD + RP \tag{1}$$

where K is the required return on common equity, YD is the utility's current cost of long-term debt (yield) and RP is the risk premium. Since YD is directly measurable, and *if* RP can be properly measured, K can then be directly estimated.[4] However, there are two general problems with the implementation of a risk premium methodology:

1. The estimation of RP is often based on historical earned returns, which may or may not be indicative of *required* returns; and
2. The level of RP may not be constant through time. In particular, there may be an inverse relationship between interest rates and risk premia.[5]

To address the first problem we use Commission-allowed returns as a reasonable surrogate for required returns, with a partial adjustment feature, as will be discussed later. Commissions and their staff spend a significant amount of time in rate cases considering the determination of a utility's appropriate return on equity. As discussed earlier, the primary method employed is the DCF method, which, when performed properly, estimates the required return on equity.[6] Furthermore, Commission-allowed returns may represent better estimates of equity costs, than DCF methods using analysts' forecasts, since Commissions comprehend a wide variety of cost of capital methods.

For illustration we have arrayed risk premia by year in Table 1. For comparative purposes we also show the estimated risk premia using the long-term US Treasury bond yield. Note that there is a general upward trend in risk premia associated with Moody's utility bond yields, which occurs during a period of generally decreasing interest rates. Furthermore, the estimated risk premia are less than those reported in Harris and Marston (1992). This can be attributed to two factors. First, utilities are generally less risky than the S&P 500 which were used in the Harris and Marston study, with corresponding lower required returns. Second, Commission-allowed returns may incorporate lower DCF growth rates than the analysts' forecasts used by Harris and Marston.

Finally, risk premia for Treasury bonds, shown in Table 1, appear to be fairly stable, albeit with a slight upward drift over the 1982–93 period. Moody's yields fell by much more (777 basis points) over that period, than did Treasury yields (578 points). An explanation for this is provided in Berry (1995). As shown there, although there is a close one-to-one relationship between Moody's utility bond yields and Treasury yields, interest rate risk had a significant impact on Moody's

Table 1. Equity Risk Premia

Year (1)	US Treasury Bond Yields (2) (%)	Allowed Return on Equity (3) (%)	Equity Risk Premia on Treasury Yields [(3)-(2)] (4) (%)	Moody's Utility Bond Yields (5) (%)	Equity Risk Premia on Moody's Yields [(3)-(5)] (6) (%)
1982	12.23	15.46	3.23	15.33	0.13
1983	10.84	15.18	4.34	13.31	1.87
1984	11.99	15.25	3.26	14.03	1.22
1985	10.75	14.38	3.63	12.29	2.09
1986	8.14	13.2	5.06	9.46	3.74
1987	8.64	12.86	4.22	9.98	2.88
1988	8.98	12.82	3.84	10.45	2.37
1989	8.58	12.92	4.34	9.66	3.26
1990	8.74	12.63	3.89	9.76	2.87
1991	8.16	12.41	4.25	9.21	3.20
1992	7.52	11.84	4.32	8.57	3.27
1993	6.45	11.54	5.09	7.56	3.98
Change 1982–93	−5.78	−3.92	+1.86	−7.77	+3.85

Note: 1993 data are partial year.

yields. The decrease in interest rate risk during the 1980s, consequently, caused an incremental decrease in Moody's yields, in excess of that corresponding to the decrease in Treasury yields.[7] As will be discussed later, although the risk premia associated with Treasury bonds appear to be fairly stable during the 1982–93 period, there are specific reasons for that, which will not necessarily be repeated in the future.

In our regression analysis we use allowed returns and the corresponding bond yields for that utility's Moody's bond rating from 6 months earlier than the date of the Commission rate order.[8] This provides a better matching since the evidentiary record on the required return on equity is usually developed some months before the date of the rate order. The data on allowed returns was obtained from various editions of *Public Utilities Fortnightly* (1983–93).[9] The data on Moody's bond yields was obtained from various editions of *Moody's Public Utility Manual* (1982–93). This yielded a total of 1226 rate case observations over the period 1982–93. For each month we averaged the cross-sectional data to obtain 130 usable time series observations.[10]

Consistent with Equation (1), let K_t^* represent the required return on equity at time t such that

$$K_t^* = RP_t + YD_t \qquad (2)$$

where RP_t and YD_t are the risk premium and current cost of debt at time t, respectively. To allow for a varying risk premium set

$$RP_t = \alpha + \beta YD_t. \qquad (2a)$$

Postulate a regulator adjustment function of the form:

$$K_t - K_{t-1} = \gamma(K_t^* - K_{t-1}), \quad 0 < \gamma < 1 \qquad (3)$$

where K_t is the allowed return at time t and γ is the adjustment factor. This equation implies an inertia on the part of regulators such that with a change in the required return on equity from the prior period's allowed return on equity, $K_t^* - K_{t-1}$, the regulator only moves part way to a new allowed return. The greater the value of γ, the greater the degree of regulator adjustment.[11]

Substitution of Equation (2) into Equation (3) yields

$$K_t = \gamma RP_t + \gamma YD_t + (1-\gamma)K_{t-1} \qquad (4)$$

or

$$K_t = \alpha\gamma + (1+\beta)\gamma YD_t + (1-\gamma)K_{t-1} \qquad (4a)$$

For purposes here, we used the allowed return from 1 month earlier. Regulators are aware of recent allowed returns and will likely partially base their current allowed return awards on those recent historical allowed returns, consistent with Equation (3).[12] We then performed an ordinary least squares regression of the allowed returns on the corresponding bond yields and lagged allowed returns. This resulted in the following regression equation:

$$K_t = 0.03337 + \underset{(6.11)}{0.22301\,YD} + \underset{(8.58)}{0.56788K_{t-1}},$$
$$(\text{Durbin-Watson} = 2.41,\ R^2 = 0.905). \quad (5)$$

The t-statistics are shown in parentheses, and indicate significance for both independent variables at the 1% level. The implied value of γ, the adjustment factor, is $1 - 0.56788 = 0.43212$.

The implied risk premium equation, corresponding to Equation (2a), is

$$RP_t = 0.07722 - 0.48392\,YD_t. \quad (6)$$

Equation (6) indicates the presence of an inverse relationship between risk premia and interest rates. For every 100 basis point drop in interest rates, the risk premium *increases* by approximately 48 basis points and the cost of equity decreases by approximately 52 basis points. Conversely, for every 100 basis point increase in interest rates, the risk premium *decreases* by approximately 48 basis points and the cost of equity increases by approximately 52 basis points.

To the extent interest rate variability is a major factor in the level of capital costs, we would expect to empirically observe this inverse relationship between risk premia and interest rates.[13] That is, as interest rate variability increases, interest rate risk increases, interest rates increase, and risk premia fall since utility equity costs change very little, or decrease, for the reasons mentioned in the introduction. The converse would be true in the case of a decrease in interest rate variability.[14]

An alternative formulation of Equation (1) is

$$K_t^* = RP_t + GOV_t. \quad (7)$$

where GOV_t is the yield on long-term US Treasury bonds and RP_t is the corresponding risk premium. Performing a similar regression analysis with GOV instead of YD produces:

$$K_t = 0.1981 + \underset{(3.74)}{0.16016GOV_t} + \underset{(12.09)}{0.73703K_{t-1}},$$
$$(\text{Durbin-Watson} = 2.56,\ R^2 = 0.889). \quad (8)$$

The R^2 is statistically significant at the 1% level with both independent variables statistically significant.

The implied risk premium equation, corresponding to Equation (2a), is

$$K_t^* = 0.07533 - 0.39096GOV_t. \quad (9)$$

This formulation, too, indicates an inverse relationship between risk premia, measured relative to Treasury bonds, and Treasury bond yields. In particular, note that for a given 100 basis point increase in interest rates the risk premium decreases by 39 basis points. The relative change in risk premia is not as great, which is attributable to less interest rate variability and interest rate risk associated with Treasury bonds.[15] Over the 1982–93 period, while Treasury yields fell by 578 basis points, Moody's utility bond yields fell by 777 basis points.

REGRESSION RESULTS WITH BOND YIELD VARIABILITY

A factor that could directly and significantly affect risk premia is investor-perceived variability in utility bond yields. It is likely that historical variability in those bond yields would impact investor perceptions of interest rate risk and increase utility bond yields. Furthermore, to the extent that there is some substitutability between utility common stocks and utility bonds, as interest rate risk associated with bonds increases, investors may increase their preferences for utility stocks. This should tend to decrease required returns on utility common stock.[16] Both of these effects will tend to reduce the risk premium when utility bond interest rate risk increases.

While some of that interest rate variability may be picked up in the data on interest rate levels, those interest rate levels also reflect other factors, such as general tightness (or laxity) in capital market conditions, prevalence of call provisions, and differential tax wedges.[17] Thus, we performed a regression analysis that explicitly included a measure for interest rate variability. An obvious measure is the standard deviation (S.D.) in interest rates in the immediate past. If our hypothesis is correct, an increase in the S.D. should decrease RP.

We considered two different historical timeframes for estimating the S.D.: 3 years and 5 years (*SD3* and *SD5*, respectively). For example, with the 3 year time frame, the S.D. at month n is calculated using the 36 months prior to month n. With the 5-year time frame, the prior 60 months were used. Each of these measures was calculated separately for bond yields for Moody's *Aaa*, *Aa*, *A* and *Baa* utility bonds and then averaged across bond ratings to obtain the average *SD3* and *SD5* for each month.

Table 2. Regression Results With *YD*, Dependent Variable = *K*

Variable				
Constant	0.1077	0.0981	0.0790	0.1001
t	−0.0002** (−7.25)	−0.0002** (−6.16)	−0.0001** (−4.47)	−0.0002** (−6.09)
YD	0.2584** (7.55)	0.2032** (6.12)	0.1947** (5.57)	0.1950** (5.89)
$SD3$	−0.5087** (−5.31)			
$RMSD3$		−0.1695** (−3.91)		
$SD5$			−0.1282 (−1.43)	
$RMSD5$				−0.1307** (−3.83)
K_{t-1}	0.1302 (1.59)	0.2131* (2.60)	0.3312** (4.18)	0.2099* (2.53)
R^2	0.9332**	0.9270**	0.9194**	0.9267**
Durbin-Watson	2.06	2.08	2.15	2.07
N	130	130	130	130

Note: t-statistics in parentheses. * and** indicate significance at the 5% and 1% levels, respectively.

These are reasonable historical time frames for purposes of estimating forward-looking investor expectations of interest rate risk. Of course, if there has been little change in these S.D.s during the sample period, then none of this matters. However, as discussed in Berry (1995) there has been significant volatility in bond yields. This has led to sharp increases in S.D.s in the early 1980s (almost triple the level in the 1970s), with some decrease in the latter 1980s.

Another way of gauging this variability is to consider the deviation of the immediately preceding month's yield from the relevant prior months' yields. As in the case of S.D.s, 3- and 5-year lags were considered. For example, in the case of 3 years, the formula used to calculate the root mean square deviation (*RMSD*) in month n is

$$RMSD3(n) = \left(\left[\sum_{i=n-36}^{n-1} (YD_{n-1} - YD_i)^2\right]/36\right)^{1/2} \tag{10}$$

where YD_{n-1} is the yield in the immediately preceding month and YD_i, $i = 1, \ldots, n-1$, corresponds to the yields in the prior months. An analogous formula for *RMSD* (*RMSD5*) was used for the case of 5 years. As in the cases for *SD3* and *SD5*, different data series were calculated for the four Moody's bond ratings and then averaged across bond ratings.

The *RMSD* may be an appropriate measure of the risk perceived by an investor since it measures the potential interest rate swings (based on prior months' interest rates) relative to the immediately preceding month's yield. In contrast, the variable S.D. measures interest variability over a prior time frame relative to the mean over that same time frame. That mean does not necessarily equal a current yield, and hence may underestimate investor perceptions with regard to potential interest rate variability. Thus, usage of the *RMSD* assumes that, in month n, investors may look at month $n-1$'s yield relative to prior months' interest rates to gauge the full impact of any potential interest rate swing. Note that, as discussed in Berry (1995) the trends in *RMSD* are similar to those of S.D.To comprehend for the possibility of a time trend in risk premia we included a monthly trend variable, t. This type of variable was discussed in Morin (1994), pp. 291–292) and was statistically significant there.

Our more complete formulation using *SD3* is then:

$$K_t^* = RP_t + YD_t \tag{11}$$

where

$$RP_t = \alpha + \beta t + \delta YD_t + \theta SD3_t. \tag{11a}$$

Assuming a regulator adjustment function as shown in Equation (3) and substituting Equations (11) and (11a) into Equation (3) produces our regression equation:

$$K_t = \alpha\gamma + \beta\gamma t + (\delta + 1)\gamma YD_t + \theta\gamma SD3_t + (1-\gamma)K_{t-1}. \tag{12}$$

Similar regression equations were used for *SD5*, *RMSD3* and *RMSD5*, where each of those variables were used in place of *SD3*. Our hypotheses are that the coefficient associated with t will be negative (consistent with Morin), the coefficient associated with *YD* will be positive, and that the coefficient associated with *SD3* (*SD5*, *RMSD3*, *RMSD5*) will be negative, as investors shift their relative preference to utility stock as interest rate risk on utility bonds increase.

Table 3. Implied Risk Premium Results, Dependent Variable = *RP*

Variable				
Constant	0.1238	0.1247	0.1181	0.1267
t	−0.0002	−0.0003	−0.0002	−0.0003
YD	−0.7029	−0.7418	−0.7089	−0.7532
$SD3$	−0.5849			
$RMSD3$		−0.2154		
$SD5$			−0.1917	
$RMSD5$				−0.1654

Table 5. Implied Risk Premium Results, Dependent Variable = *RP*

Variable				
Constant	0.1366	0.1390	0.1208	0.1408
t	−0.0004	−0.0003	−0.0002	−0.0003
GOV	−0.7906	−0.8169	−0.7399	−0.8215
$SD3$	−0.3357			
$RMSD3$		−0.1848		
$SD5$			0.1045	
$RMSD5$				−0.1655

The dependent variable, K, was then regressed on the three independent variables: time, yield and measures of variability in yields. Those four regression results are shown in Table 2.

Note that the regression slope coefficients are generally significant, although the coefficient for $SD5$ was not. There is a statistically significant downward time trend, which is consistent with the result in Morin. The effects of YD on K are positive and significant. Three of the four coefficients associated with interest rate risk, $SD3$, $RMSD3$ and $RMSD5$ are significant and negative as was hypothesized. Finally, note that all of the slope coefficients associated with YD are significantly less than one, which supports the hypothesis that as interest rates decrease risk premia increase.

As can be seen in Table 2, the adjustment coefficients are in the range 67–87%, which are higher than the adjustment coefficient of 43% from Equation (5). This can be explained by noting that Equation (5) does not include the other factors shown in Table 2 (in particular, interest rate variability). Consequently, the adjustment coefficient measurement in Equation (5) is clouded by the effects of the other factors. It appears that regulators are not adjusting K to K^* very much (only 43%), simply because K is also reacting to other factors not captured in Equation (5). Table 2 properly captures those additional effects and isolates the larger adjustment coefficient effect.

The implied risk premium results, corresponding to Equation (11a), are shown in Table 3. As can be seen there, the coefficient associated with YD is between approximately -0.70 and -0.75. This indicates that each increase in utility bond yields of 100 basis points produces a decrease in the risk premium of 70 to 75 basis points. Increases in interest rates result in decreases in risk premia. Furthermore, the negative slope coefficients associated with interest rate risk, imply smaller risk premia as hypothesized. The trend variable in Table 3 has a negative slope, which is consistent with results reported in Morin (1994).[18]

To some extent the variable YD may include both the effects of general tightness or laxity in financial markets and interest rate risk. In order to better focus on the two separate factors, it would be appropriate to replace YD with GOV in

Table 4. Regression Results With *GOV*, Dependent Variable = *K*

Variable				
Constant	0.0781	0.0818	0.0639	0.0874
t	−0.0002** (−4.85)	−0.0002** (−5.10)	−0.0001** (−3.21)	−0.0002** (−5.44)
GOV	0.1197** (2.99)	0.1078** (2.66)	0.1376** (3.18)	0.1108** (2.80)
$SD3$	−0.1919 (−1.85)			
$RMSD3$		−0.1088* (−2.21)		
$SD5$			0.0553 (0.54)	
$RMSD5$				−0.1027** (−2.71)
K_{t-1}	0.4283** (5.30)	0.4113** (5.04)	0.4709** (6.01)	0.3794** (4.55)
R^2	0.9092**	0.9102**	0.9069**	0.9119**
Durbin–Watson	2.18	2.17	2.24	2.13
N	130	130	130	130

Note: t-statistics are in parentheses. * and ** indicate significance at the 5% and 1% levels, respectively.

Equations (11) and (11a), since *GOV* will more directly reflect changes in the supply and demand for loan funds, without the effect of utility bonds' interest rate risk. The corresponding equations with *SD3* are:

$$K_t^* = RP_t + GOV_t \qquad (13)$$

$$RP_t = \alpha + \beta t + \delta GOV_t + \theta SD3, \qquad (13a)$$

These Equations focus on the relationship between utility stocks and government bonds. Assuming an adjustment mechanism as shown in Equation (3) a regression equation analogous to Equation (12) can be developed. Those regression results are shown in Table 4 and are similar to those from Table 2. However, note that the slope coefficients associated with *GOV* are smaller than those associated with *YD* in Table 2. This is consistent with the results in Berry (1995) wherein it was shown that *GOV* had a larger effect on utility bond yields than on utility common stock dividend yields. Given an imperfect, although positive, relationship between Treasury bonds and utility bonds, and an imperfect relationship between utility bonds and utility stocks, it naturally follows that there would be an even more imperfect relationship between Treasury bonds and utility stocks. This means that there is more substitutability between utility common stocks and utility bonds than between utility stocks and US Treasury bonds. A further point to note from Table 4 is that the slope coefficients associated with S.D. are statistically insignificant, while those associated with *RMSD* are significant.

The implied risk premium results, corresponding to Equation (13a) are shown in Table 5. As can be seen there, the coefficient associated with *GOV* is between approximately -0.74 and -0.82 less than those associated with *YD* in Table 3. This is consistent with the point raised above concerning relative substitutability between stocks and bonds. An increase in Treasury yields of 100 basis points produces an increase of 18–26 basis points in the cost of equity, and a corresponding decrease in the risk premium of 74–82 basis points. In sharp contrast to the reported results in Table 1, controlling for other factors, risk premia relative to Treasury yields are not necessarily stable, but change as Treasury yields change. Increases in Treasury yields result in decreases in risk premia, and those decreases are greater than those associated with similar increases in utility bond yields. Furthermore, the negative slope coefficients associated with utility bond interest rate risk, imply smaller risk premia as hypothesized. The trend variable in Table 5 has a negative slope, which is consistent with results reported in Morin (1994), as well as in Table 3.

CONCLUSIONS

This paper examined, through regression analysis, the possibility that there is an inverse relationship between risk premia and both interest rates and interest rate risk in the utility industry. We demonstrated that that is the case over the 1982–93 time period. Furthermore, it was shown that there is a statistically significant basis for asserting that risk premia increase as interest rates decrease. Our analysis also indicated that there was a downward time trend in risk premia in that period. All of these phenomena occurred with either utility bond yields or long-term US Treasury bond yields. However, for an equivalent increase in either utility bond yields or Treasury yields, required equity returns increase by a slightly greater amount with regard to utility bond yields.

It was also shown that regulators may exhibit an inertia in their setting of allowed returns, such that they move partially to the new required return, in the event capital conditions warrant a change. The degree of movement is in the range of 50–80% relative to the prior month's allowed return.

There are several policy implications from the above analysis. First, when regulators use the risk premium method for setting the allowed return on equity, they should consider the degree of recent interest rate variability and consequent interest rate risk, in comparing utility common stocks and utility bonds. The appropriate risk premium will be narrower the greater the interest rate risk. As demonstrated here, the better measure of interest rate risk is *RMSD*, not S.D. Second, objective regulators who attempt to utilize the risk premium method should implicitly compensate for the indicated regulator inertia. For example, calculate the risk premium using K^*, rather than K. Third, while Table 1 implies that risk premia relative to Treasury bonds are more stable, that is not the case when consideration is made for other factors, as shown in Tables 4 and 5. There is not necessarily any gain in precision in using a risk premium method based on Treasury bonds.

Fourth, if the US enters a period of relative stability in interest rates, we are likely to see utility risk premia increase, a phenomenon utility executives nor regulators have any degree of control over. This widening will not occur because of increases in required equity returns, but because of relatively lower interest rates and less interest rate risk.

NOTES

1. See Bonbright *et al.*, 1988 (pp. 317–28) for a discussion of these methods.
2. Gordon and Halpern (1976) show that an increase in variable and uncertain inflation will theoretically decrease the spread between bond and share yields. This acts through the Fisher effect and the resultant increase in interest rate uncertainty. Examples of rate cases where this argument has been made are Arkansas Public Service Commission (1987), Docket No. 87-070-U, Federal Energy Regulatory Commission (1986), Docket Nos. EL86-58-000 and EL86-59-000, Hawaii Public Utility Commission, Docket No. 4156, Kentucky Public Service Commission, Case No. 8045, and Pennsylvania Public Utility Commission, Docket R-811510.
3. These points are noted in Brigham *et al.* (1985) and Taylor and Peake (1982).
4. See Ibbotson Associates (1993), Carleton *et al.* (1983), Brigham *et al.* (1985) and Harris (1986) for a discussion of risk premia.
5. See Brennan (1982), Brigham *et al.* (1985) and Harris (1986). Other sources are Harris and Marston (1992), Gordon and Halpern (1976) and Federal Energy Regulatory Commission Staff (1992).
6. This approach was also taken in the Federal Energy Regulatory Commission (1992) Staff study.
7. During the same period, any interest rate risk associated with Treasury bonds was not as large, nor did it exhibit as large a decrease.
8. Given the rate case process (testimony, hearing, order writing) a 6 month lag is reasonable. However, if the 6 month period is either too long or short, the analysis here would only result in a mis-estimate of the intercept term, not the slope coefficients. For example, in a period of increasing interest rates(non-accelerating), if the appropriate lag should have been only 3 months, the 6 month lag will result in an over-estimate of the intercept term, but no mis-estimate of the slope terms. With a non-decelerating decrease in interest rates, the intercept term will be under-estimated, with no mis-estimated slope terms. The focus of this paper is on the slope terms. Furthermore, regression analyses was also performed using (a) bond yields contemporaneous with the date of the allowed return and (b) bond yields from 12 months earlier. In both those cases, the Durbin–Watson statistics were worse and the corresponding R^2 were less than with the 6 month lag. Additionally, the slope coefficients for the *YD* and *GOV* variables were not as large, nor as significant as in the 6 month lag case. Consequently, the 6 month lag scenario was utilized here.
9. For the electric and gas rate cases the data was from *Public Utilities Fortnightly's* 'Annual Surveys', while the telecommunications data was from *Public Utilities Fortnightly's* 'Selected Utility Rate Filings'.
10. The data was aggregated into monthly data for three reasons. First, Durbin–Watson statistics can then be sensibly calculated. Second, this approach is consistent with prior studies. Third, this aggregation facilitates the partial adjustment feature. There were months when there were no reported allowed returns, which decreased our total sample size.
11. See Johnston, 1972 (pp. 300–301), for discussion of this technique.
12. This approach implicitly assumes that regulators focus on allowed returns in other jurisdictions in the prior month. This is reasonable for two reasons. First, there is a certain amount of 'peer pressure' amongst regulators wherein they generally do not want their own jurisdiction's allowed returns to be out of line with other jurisdictions, unless justified by general financial and economic circumstances (such as changes in interest rates). Second, the last allowed rate of return for a particular utility may be anywhere from 6 months to 3 years earlier. Modelling those differing periods adds unnecessary complexity to the analysis, in light of the first point raised.
13. See Berry (1995) for an empirical investigation of the impact of interest rate variability on the level of interest rates.
14. Other explanations for an inverse relationship between interest rates and risk premia have to do with call provisions and tax rates. In a high interest rate environment firms will include more call provisions in new bond issues, for which bond investors require even higher interest rate compensation. Additionally, with increasing interest rates, the tax wedge applied to interest on bonds grows relative to that on common stock due to the favorable tax treatment on the capital gains component of stock returns.
15. It could also be attributable to increased utility credit risk during that period.
16. This effect can be readily observed in the DCF method where K is calculated as $D/P+g$. D is the expected dividend, P is the stock's market price, and g is the investor-expected long-term growth rate in dividends. As P increases because of investors' relative preference for utility stocks, K will decrease.
17. As shown in Berry (1995), the impact of the tightness of capital markets has differential effects on interest rates and common stock dividend yields.
18. This negative slope coefficient associated with the time variable also provides an explanation as to why the positive interest rate slope coefficients are

smaller in Table 3 than that reflected in Equation (2). Throughout the 1982–93 period, interest rates were generally decreasing, which according to the results in Table 3, will lead to decreases in required equity returns. However, during that same period the trend variable t was increasing. This increasing trend variable implies an additional source for decreases in required equity returns over that time period. Since Equation (2) does not explicitly separate out the trend variable, the overall effect in Equation (2) includes both of these effects, which will make the Equation (2) slope coefficient larger.

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Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return

Robert S. Harris

Robert S. Harris is a member of the faculty of the University of North Carolina at Chapel Hill. He is also an Associate Editor of Financial Management.

I. Introduction

Shareholder required rates of return play key roles in establishing economic criteria for resource allocation in many corporate and regulatory decisions. Theory dictates that such returns should be forward-looking return requirements that take into account the risk of the specific equity investment.

Estimation of such returns, however, presents numerous and difficult problems. Although theory clearly calls for a forward-looking required return, investigators, lacking a superior alternative, often resort to averages of historical realizations. One primary example is the determination of equity required return as a "least risk" rate plus a risk premium where an equity risk premium is calculated as an average of past differences between equity returns and returns on debt instruments. The historical studies of Ibbotson *et al.* [9] have been used frequently to implement this approach.[1] Use of such historical risk premia assumes that past realizations are a good surrogate for future expectations and that risk premia are roughly constant over time. Additionally, the choice of a time period over which to average data under such a procedure is essentially arbitrary. Carleton and Lakonishok [3] demonstrate empirically some of the problems with such historical premia when they are disaggregated for different time periods or groups of firms.

Recently Brigham, Shome, and Vinson [2] surveyed work on developing *ex ante* equity risk premia with particular emphasis on regulated utilities. They presented their own risk premia estimates, which make use of financial analysts' forecasts as surrogates for investor expectations.

The current paper follows an approach similar to Brigham *et al.* and derives equity required returns and risk premia using publicly available expectational

Thanks go to Ed Bachmann, Rich Harjes, and Hamid Mehran for computational assistance and to Bill Carleton, Pete Crawford, and Steve Osborn for many discussions. I gratefully acknowledge financial support from the UNC Business Foundation and the Pogue Foundation and thank Bell Atlantic for supplying data for this project. Finally, I thank colleagues at UNC for their helpful comments.

[1]Many leading texts in financial management use such historical risk premia to estimate a market return. See for example, Brealey and Myers [1]. Often a market risk premium is adjusted for the observed relative risk of a stock.

Exhibit 7. Changes in Equity Risk Premia Over Time — Entries are Coefficient (t-value)

Regression	Intercept	i_{20}	σ_g	$i_c - i_{20}$	R^2
A. SP500: Dependent Variable is Equity Risk Premium*					
1.	0.140	−0.632			0.43
	(8.15)†	(−4.95)†			
2.	0.118	−0.660	0.754		0.58
	(7.10)†	(−5.93)†	(3.32)†		
3.	0.069	−0.235		1.448	0.57
	(3.44)†	(−1.76)		(4.18)†	
4.	0.030	−0.177	0.855	1.645	0.79
	(2.17)†	(−2.07)†	(4.68)†	(7.63)†	

Regression	Intercept	i_{20}	σ_g	$i_u - i_{20}$	R^2
B. SPUT: Dependent Variable is Equity Risk Premium*					
1.	0.110	−0.510			0.37
	(7.35)†	(−4.41)†			
2.	0.101	−0.543	0.805		0.41
	(6.28)†	(−4.68)†	(1.42)		
3.	0.051	−0.259		1.432	0.80
	(5.54)†	(−4.05)†		(8.87)†	
4.	0.049	−0.287	0.387	1.391	0.80
	(5.15)†	(−3.87)†	(0.75)	(8.14)†	

*All variables are defined in Exhibit 1 and graphed in Exhibit 6. Regressions were estimated for the 36 month period January 1982–December 1984 and were corrected for serial correlation using the Prais-Winsten method. For purposes of this regression variables are expressed in decimal form, *e.g.*, 14% = 0.14.

†Significantly different from zero at 0.05 level using two-tailed test

cause of lower variability over time in the dispersion of FAF for utility stocks as compared to equities in general. The yield spread between utility and government bonds is significantly positively related to utility equity risk premia. And, as in the case of stocks in general, introduction of this spread substantially reduces the independent effect of interest rate levels on equity risk premia.

Given the short time series (36 months), tests for the stability of the relationships found in Exhibit 7 present difficulties. As a check, the relationships were reestimated dividing the data into two 18-month periods. For stocks in general (SP500), coefficients on σ_g and $(i_c - i_{20})$ were positive in all regressions and significantly so, except in the case of $(i_c - i_{20})$ for the second 18-month period. The coefficient of i_{20} was significantly negative in both periods. This confirms the general findings for the SP500 in Panel A of Exhibit 7. For utility stocks, results for the subperiods also matched the entire period results. The coefficients of $(i_u - i_{20})$ were significantly positive in both subperiods while those of σ_g were insignificantly different from zero. The level of interest rates (i_{20}) had a significant negative effect in both subperiods.

In summary, the estimated risk premia change over time and the patterns of such change are directly related to changes in proxies for the risks of equity investments. Risk premia for both stocks in general and utilities are inversely related to the level of government interest rates but positively related to the bond yield spreads which proxy for the incremental risk of investing in equities rather than government bonds. For stocks in general, risk premia also increase over time with increases in the general level of disagreement about future corporate performance.

VI. Conclusions

Notions of shareholder required rates of return and risk premia are based in theory on investors' expectations about the future. Research has demonstrated the usefulness of financial analysts' forecasts for such expectations. When such forecasts are used to derive equity risk premia, the results are quite encouraging. In addition to meeting the theoretical requirement of using expectational data, the procedure produces estimates of reasonable magnitude that behave as economic theory would predict. Both over time and across stocks, the risk premia vary directly with the perceived riskiness of equity investment.

The approach offers a straightforward and powerful aid in establishing required rates of return either for corporate investment decisions or in the regulatory arena. Since data are readily available on a wide range of equities, an investigator can analyze various proxy groups (*e.g.*, portfolios of utility stocks) appropriate for a particular decision. An additional advantage of the estimated risk premia is that they allow analysis of changes in equity return requirements over time. Tracking such changes is important for managers facing changing economic climates.

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Equity Risk Premium

Data Point	Value	Data as of
Kroll Recommended	5.50%	03/13/2024
Supply-side Long-term (1926–2023)	6.22%	12/31/2023
Historical Long-term (1926–2023)	7.17%	12/31/2023

CRSP Deciles Size Study - Data as of 12/31/2023

Companies Ranked	Market Value of Common Equity		
Decile	**Low End Breakpoint**	**High End Breakpoint**	**Size Premium**
Mid Cap	3,011.22	14,820.05	0.66%
Low Cap	555.88	3,010.81	1.24%
Micro Cap	1.58	554.52	2.91%
Breakdown of CRSP Deciles 1 - 10			
1	36,942.98	2,662,326.05	-0.06%
2	14,910.72	36,391.11	0.46%
3	7,493.61	14,820.05	0.61%
4	4,622.26	7,461.28	0.64%
5	3,011.22	4,621.79	0.95%
6	1,864.29	3,010.81	1.21%
7	1,050.08	1,862.49	1.39%
8	555.88	1,046.04	1.14%
9	213.04	554.52	1.99%
10	1.58	212.64	4.70%
Breakdown of CRSP 10th Decile			
10A	97.46	212.64	3.29%
10W	153.80	212.64	2.38%
10X	97.46	153.67	4.43%
10B	1.58	97.40	7.64%
10Y	57.82	97.40	6.22%
10Z	1.58	57.45	10.73%

Exhibit 7.2: Largest Company (by market capitalization) in CRSP (NYSE/NYSE MKT/NASDAQ) Deciles and Size Groupings
September 30, 2018

Decile	Company Name	Recent Market Capitalization (in $thousands)
1-Largest	Apple Inc	1,073,390,566
2	Dollar General Corp New	29,022,867
3	Yum China Holdings Inc	13,455,802
4	O G E Energy Corp	7,254,230
5	Dolby Laboratories Inc	4,503,549
6	Owens Ill Inc	2,992,251
7	Prestige Consumer Healthcare Inc	1,960,201
8	Group 1 Automotive Inc	1,292,224
9	Federal Agricultural Mort Corp	727,843
10-Smallest	Foresight Energy Lp	321,578

Source of underlying data: CRSP databases © 2019 Center for Research in Security Prices (CRSP®), The University of Chicago Booth School of Business (2018). To learn more about CRSP, visit www.crsp.com.

In the following sections we provide an example of (i) calculating a CRSP Deciles Size Study premium and (ii) a Risk Premium Report Study size premium, using example data from each of the two data sets.

Size Premium Calculation: CRSP Deciles Size Study

In the 2019 data year of the Cost of Capital Navigator, the CRSP Deciles Size Study are calculated over the years 1926–2018. The following statistics are calculated over this time period:

- The "historical" average annual long-term equity risk premium is 6.91%.
- The average annual risk-free rate is 4.97%.
- CRSP Decile 9 average annual return equals 16.65%.
- CRSP Decile 9 OLS beta equals 1.34.

The beta-adjusted size premium for CRSP Decile 9 is calculated as follows:

Size Premium$_{\text{CRSP Decile 9}}$ *= actual excess return – excess return predicted by CAPM*

The *actual* excess return of Decile 9 is 11.69% (16.65% – 4.97%) (difference due to rounding), and the excess return that CAPM *predicted* is 9.23% (1.34 x 6.91%) (difference due to rounding). The size premium for CRSP Decile 9 is therefore 2.46%, which is "what actually happened" (11.69%) minus "what CAPM predicted" (9.23%). This is what is meant when we say that the beta of smaller

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The Quarterly Review of Economics and Finance
43 (2003) 578-582

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Short communication

Utility stocks and the size effect-revisited

Thomas M. Zepp*[1]

Utility Resources, Inc., 1500 Liberty Street S.E., Suite 250, Salem, OR 97302, USA

Received 7 January 2002; received in revised form 27 August 2002; accepted 29 August 2002

Abstract

Wong concluded there is weak empirical support that firm size is a missing factor from the capital asset pricing model for industrial stocks but not for utility stocks. Her weak results, however, do not rule out the possibility of a small firm effect for utilities. The issue she addressed has important financial implications in regulated proceedings that set rates of return for utilities. New studies based on different size water utilities are presented that do support a small firm effect in the utility industry.

Keywords: Utility stocks; Beta risk; Firm size

Annie Wong concludes there is some weak evidence that firm size is a missing factor from the capital asset pricing model ("CAPM") for industrial stocks but not for utility stocks (Wong, 1993, p. 98). This "firm size effect" is an observation that small firms tend to earn higher returns than larger firms after controlling for differences in estimates of beta risk in the CAPM. Wong notes that if the size effect exists, it has important implications and should be considered by regulators when they determine fair rates of return for public utilities. This paper re-examines the basis for her conclusions and presents new information that indicates there is a small firm effect in the utility sector.

1. Reconsideration of the evidence provided by Wong

Wong relies on Barry and Brown (1984) and Brauer (1986) to suggest the small firm effect may be explained by differences in information available to investors of small and large firms.

* Tel.: +1-503-370-9563; fax: +1-503-370-9566.
E-mail address: tzepp@ur-inc.com (T.M. Zepp).

1062-9769/02/$-see front matter
PII: S1062-9769(02)00172-2

She states that requirements to file reports and information generated during regulatory proceedings indicate the same amount of information is available for large and small utilities and thus, if the differential information hypothesis explains the small firm effect, then the uniformity of information available among utility firms would suggest the size effect should not be observed in the utility industry. But contrary to the facts she assumes, there are differences in information available for large and small utilities. More parties participate in proceedings for large utilities and thus generate more information. Also, in some jurisdictions smaller utilities are not required to file all of the information that is required of larger firms. Thus, if the small firm effect is explained by differential information, contrary to Wong's hypothesis, differences in available information suggests there is a small firm effect in the utility industry. Wong did not discuss other potential explanations of the small firm effect for utilities.[2]

Wong's empirical results are not strong enough to conclude that beta risks of utilities are unrelated to size. In the period 1963-1967, when monthly data were used to estimate betas, her estimates of utilitybetas as well as industrial betas increased as the size of the firms decreased, but she did not find the same inverse relationship between size and beta risk for utilities in other periods. Being unable to demonstrate a relationship between size and beta in other periods may be the result of Wong using monthly, weekly and daily data to make those beta estimates. Roll (1980) concluded trading infrequency seems to be a powerful cause of bias in beta risk estimates when time intervals of a month or less are used to estimate betas for small stocks. When a small stock is thinly traded, its stock price does not reflect the movement of the market, which drives down the apparent covariance with the market and creates an artificially low beta estimate.

Ibbotson Associates (2002) found that when annual data are used to estimate betas, beta estimates for the smaller firms increase more than beta estimates for larger firms. Table 1 compares Value Line (2000) beta estimates for three relatively small water utilities that are made with weekly data and an adjusted beta estimated with pooled annual data for the utilities for the 5-year period ending in December 2000. In making the latter estimate, it is assumed that the underlying betafor each of water utilities is the same. The!-statistics for the unadjusted beta

Table 1
Beta estimates reported by Value Line and estimated with pooled annual returns for relatively small water utilities

	Value Line[a]	Estimated with annual data[b]
Connecticut Water Service	0.45	
Middlesex Water	0.45	
SJW Corporation	0.50	
Average	0.47	0.78
t-statistic		, 2 72[c,d]

[a] As reported in Value Line (2000). Betas estimated with 5 years of weekly data.

[b] Estimated with pooled annual return premiums for the 5-year period ending December 2000. Proxy market returns are total returns for the S&P 500 index. Dummy variable in 1999 to reflect the proposed acquisition of SJW Corporation included in analysis.

[c] Significant at the 95% level.

[d] The t-statistic for the null hypothesis that the true beta is 0.18 (the derived unadjusted Value Line beta) when the estimated betas is 0.65 (the unadjusted estimated beta) is 1.97. It is significant at the 95% level.

estimate is reported in parentheses. As was found by Ibbotson Associates (2002) for stocks in general, when annual data are used to estimate betas for small utility stocks, the beta estimate mcreases.

Wong used the Fama and MacBeth (1973) approach to estimate how well firm size and beta explain future returns in four periods. She reports weak empirical results for both the industrial and utility sectors. In every one of the statistical results reported for utilities, the coefficient for the size effect has a negative sign as would be expected if there is a size effect in the utility industry butonly oneof the results was found to be statistically significant at the 5% level. With the industrial sector, though she found two cases to have a significant size effect, a negative sign for the size coefficient occurred only 75% of the time. What is puzzling is that with these weak results, Wong concludes the analysis provides support for the small firm effect for the industrial industry but no support for a small firm effect for the utility industry.

2. New evidence on risk premiums required by small utilities

Two other studies support a conclusion that small utilities are more risky than larger ones. A study made by Staff of the Water Utilities Branch of the California Public Utilities Commission Advisory and Compliance Division (CPUC Staff, 1991) used proxies for beta risk and determined small water utilities were more risky than larger water utilities. Part of the difficulty with examining the question of relative risk of utilities is that the very small utilities are not publicly-traded. This CPUC Staff study addressed that concern by computing proxies for beta risk estimated with accounting data for the period 1981-1991 for 58 water utilities. Based on that analysis, CPUC Staff concluded that smaller water utilities were more risky and required higher equity returns than larger water utilities. Following 8 days of hearings and testimony by 21 witnesses regarding this study, it was adopted by the California Public Utilities Commission in CPUC Decision 92-03-093, dated March 31, 1992.

Table 2 provides the results of another study of differences in required returns estimated from discounted cash flow ("DCF") model estimates of the costs of equity for water utilities of different sizes. The study compares average estimates of equity costs for two smaller water utilities, Dominguez Water Company and SJW Corporation, with equity cost estimates for two larger companies, California Water Service and American States Water, for the period 1987- 1997. All four utilities operated primarily in the same regulatory jurisdiction during that period. Estimates of future growth are required to make DCF estimates. Gordon, Gordon, and Gould (1989) found that a consensus of analysts' forecasts of earnings per share for the next *5* years provides a more accurate estimate of growth required in the DCF model than three different historical measures of growth. Unfortunately, such analysts' forecasts are not generally available for small utilities and thus this study assumes, as was assumed by staff at the regulatory commission, that investors relied upon past measures of growth to forecast the future. The results in Table 2 show that the smaller water utilities had a cost of equity that, on average, was 99 basis points higher than the average cost of equity for the larger water utilities. This result is statistically significant at the 90% level. In terms of the issues being addressed by Wong, the 99 basis points could be the result of differences in beta risk, the small firm effect or some combination of the two.

Table2
Small firm equity costdifferential: case studybasedona comparison ofDCF equity cost estimates for larger andsmaller California water utilities (1987-1997)

	Larger water utilitiesa			Smaller water utilitiesb			Smaller utilities minus larger utilities
	Do/Po (%)	Estimated growth(%)"	Equity cost estimate (%)d	Do/Po (%)	Estimated growth(%)"	Equity cost estimate (%)d	
1987	6.60	7.17	14.24	5.38	10.06	15.98	1.74
1988	6.75	6.30	13.48	5.81	9.08	15.42	1.94
1989	7.10	6.30	13.84	6.47	7.00	13.93	0.09
1990	7.24	6.19	13.87	6.96	7.51	14.99	1.11
1991	6.94	6.29	13.67	6.64	6.24	13.30	-0.36
1992	6.18	5.96	12.50	6.50	6.71	13.65	1.14
1993	5.32	5.68	11.30	5.49	6.31	12.15	0.85
1994	6.03	4.40	10.70	5.80	4.86	10.94	0.25
1995	6.44	3.86	10.55	6.44	4.88	11.64	1.09
1996	5.60	4.06	9.88	5.77	5.58	11.67	1.79
1997	4.93	3.31	8.40	4.52	4.89	9.64	1.23
Averarage difference							0.99
I-statistic							l. 405e

Limited to period for which Dominguez Water Company data were available. 1998 excluded due to pending buyout.
a American States Water and California Water Service.
b Dominguez Water Company and SJW Corporation.
c Average of 5- and 10-year dividends per share growth, 10-year earnings per share growth and estimates of sustainable growth from internal and external sources for the most recent 10-year period when data are available (1991-1997), otherwise most recent 5-year period (1987-1990).
d DCF equity cost as computed by California PUC staff: $k =$ <Do/Po) x (1 $+ g) + g$.
e Significant at the 90% level.

3. Concluding remarks

Wong's concluding remarks should be re-examined and placed in perspective. She noted that industrial betas tend to decrease with increases in firm size but the same relationship is not found in every period for utilities. Had longer time intervals been used to estimated betas, as was done in Table 1, she may have found the same inverse relationship between size and beta risk for utilities in other periods. She also concludes "there is some weak evidence that firm size is a missing factor from the CAPM for the industrial but not the utility stocks" (Wong,1993, p. 98), but theweak evidence provides little support for a small firmeffect existing or not existing in either the industrial or utility sector. Two other studies discussed here support a conclusion that smaller water utility stocks are more risky than larger ones. To the extent that water utilities are representative of all utilities, there is support for smaller utilities being more risky than larger ones.

Notes

1. Vice President.
2. The small firm effect could also be a proxy for numerous other omitted risk differences between large and small utilities. An obvious candidate is differentials in access to :financial markets created by size. Some very small utilities are unable to borrow money without backing of the owner. Other small utilities are limited to private placements of debt and have no access to the more liquid :financial markets available to larger utilities.

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This process will return a rate equivalent to the before-tax discount rate. This is the desired method of calculating the true effect of taxes on the discount rate. Several things are occurring here that lead to a result on a before-tax basis. Generally, the reason for calculating the IRR is that inconsistent growth rates between net cash flow and before-tax income are difficult to model in an easy-to-understand formula. Unfortunately, the downside to this process is that it is more complex and a little more difficult to explain.

Multiplicative Value Adjustments

Ad Valorem Tax Addback

The most common multiplicative value adjustment in ad valorem assessment is the addback of ad valorem taxes. Many assessors want to remove the historical bias resulting from prior valuations. Therefore, they may prefer to account for property tax within the discount rate. They do so by adding back to the discount rate the percent relationship of tax to market value. This adjustment is most similar to the linear adjustment in income. The difference is that the adjustment is a direct function of value. In other words, if the value increases, the adjustment increases directly with the value, and vice versa. This can be demonstrated by the next formula:

Formula 20.19

$$k_q = k + (o \times PV) \div PV = \frac{1 + (o \times PV)}{PV}$$

thus, $k_q = k + o$

where:

o = Percent of tax to value

And with the addition of a growth component (g), the formula expands to:

Formula 20.20

$$k_q - g = k - g + o$$

thus, $k_q = k + o$

The same formula can be used for any adjustment that is equal to a percentage of value. This holds true even in random changes in value. The only caveat is that the percent relationship to value must remain constant. This adjustment is quite powerful and easy to demonstrate, which is likely the reason for its popularity.

Flotation Costs

Another type of multiplicative value adjustment is flotation costs. Flotation costs occur when new issues of stock or debt are sold to the public. The firm usually incurs

several kinds of flotation or transaction costs, which reduce the actual proceeds received by the firm. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this reduction in proceeds, the firm's required returns on these proceeds equate to a higher return to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the cash flow to discount, or by incorporating the cost into the cost of capital. Because flotation costs are not typically applied to operating cash flow, one must incorporate them into the cost of capital.

The cost of flotation is a function of size and risk. The larger the issuance, the lower the cost as a percentage of the issuance price. Flotation costs are the greatest for equity issuance and the least for debt issuance. Preferred stock flotation costs tend to be somewhere in between. The next table shows examples of the relation of flotation cost to size of an issuance of stock that occurred during 1996 and 1997.

Company	Total Issuance	Total Flotation
Excite	39,100,000	9.46%
Team Rental	52,000,000	6.76%
Amazon	54,000,000	8.57%
IXC	89,600,000	8.67%
General Cigar	108,000,000	8.28%
Ciena	115,000,000	7.96%
Capstar	166,500,000	7.68%
General Cable	354,900,000	5.94%
Sabre	545,400,000	5.77%
Hartford Life	649,750,000	6.50%

OTHER ADJUSTMENTS TO THE COST OF CAPITAL

In the property tax arena, traditional techniques are king. Any new approaches are met with skepticism, because the results of many new techniques tend to lower the market value of the project and, thus, the taxes. This is true despite the validity of such approaches. The next paragraphs identify four "newer" techniques introduced in the ad valorem arena in the 1990s.

Ex Post and *Ex Ante* Risk Premia

The expected equity risk premium is unobservable in the market and must be estimated. For both the Capital Asset Pricing Model (CAPM) and the build-up method, *ex post* and *ex ante* risk premia are used to obtain estimates for the cost of equity.

An *ex post* risk premium is based on the assumption that historical returns are the best predictor of future returns. It is calculated by subtracting the long-term arithmetic average of the income return on long-term government bonds for the CAPM or

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RATING METHODOLOGY

Regulated Electric and Gas Utilities

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Analyst Contacts:

NEW YORK +1.212.553.1653

Michael G. Haggarty +1.212.553.7172
Associate Managing Director
michael.haggarty@moodys.com

Jim Hempstead +1.212.553.4318
Managing Director – Utilities
james.hempstead@moodys.com

Walter Winrow +1.212.553.7943
Managing Director - Global Project and Infrastructure Finance
walter.winrow@moodys.com

Jeffrey Cassella +1.212.553.1665
Vice President - Senior Analyst
jeffrey.cassella@moodys.com

Natividad Martel +1.212.553.4561
Vice President - Senior Analyst
natividad.martel@moodys.com

» contacts continued on the last page

This rating methodology replaces "Regulated Electric and Gas Utilities" last revised on December 23, 2013. We have updated some outdated links and removed certain issuer-specific information.

Summary

This rating methodology explains our approach to assessing credit risk for regulated electric and gas utilities globally. This document does not include an exhaustive treatment of all factors that are reflected in our ratings but should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector.[1]

This report includes a detailed rating grid which is a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector in most cases. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to companies in the regulated electric and gas utility industry. However, the grid is a summary that does not include every rating consideration. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions but actual importance may vary substantially. In addition, the grid in this document uses historical results while ratings are based on our forward-looking expectations. As a result, the grid-indicated rating is not expected to match the actual rating of each company.

THIS METHODOLOGY WAS UPDATED ON THE DATES LISTED AS NOTED: ON FEBRUARY 22, 2019, WE AMENDED A REFERENCE TO A METHODOLOGY IN APPENDIX E AND REMOVED OUTDATED TEXT; ON AUGUST 2, 2018, WE MADE MINOR FORMATTING ADJUSTMENTS THROUGHOUT THE METHODOLOGY; ON FEBRUARY 15, 2018, WE CORRECTED THE FORMATTING OF THE FACTOR 4: FINANCIAL STRENGTH TABLE ON PAGE 34; AND ON SEPTEMBER 27, 2017, WE REMOVED A DUPLICATE FOOTNOTE THAT WAS PLACED IN THE MIDDLE OF THE TEXT ON PAGE 7.

[1] This update may not be effective in some jurisdictions until certain requirements are met.

The grid contains four key factors that are important in our assessment for ratings in the regulated electric and gas utility sector:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength

Some of these factors also encompass a number of sub-factors. There is also a notching factor for holding company structural subordination.

This rating methodology is not intended to be an exhaustive discussion of all factors that our analysts consider in assigning ratings in this sector. We note that our analysis for ratings in this sector covers factors that are common across all industries such as ownership, management, liquidity, corporate legal structure, governance and country related risks which are not explained in detail in this document, as well as factors that can be meaningful on a company-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a grid format. The grid used for this methodology reflects a decision to favor a relatively simple and transparent presentation rather than a more complex grid that might map grid-indicated ratings more closely to actual ratings.

Highlights of this report include:

» An overview of the rated universe

» A summary of the rating methodology

» A discussion of the key rating factors that drive ratings

» Comments on the rating methodology assumptions and limitations, including a discussion of rating considerations that are not included in the grid

The Appendices show the full grid (Appendix A), our approach to ratings within a utility family (Appendix B), a description of the various types of companies rated under this methodology (Appendix C), key industry issues over the intermediate term (Appendix D), regional and other considerations (Appendix E), and treatment of power purchase agreements (Appendix F).

This methodology describes the analytical framework used in determining credit ratings. In some instances our analysis is also guided by additional publications which describe our approach for analytical considerations that are not specific to any single sector. Examples of such considerations include but are not limited to: the assignment of short-term ratings, the relative ranking of different classes of debt and hybrid securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities. A link to documents that describe our approach to such cross-sector credit rating methodological considerations can be found in the Related Research section of this report.

About the Rated Universe

The Regulated Electric and Gas Utilities rating methodology applies to rate-regulated[2] electric and gas utilities that are not Networks[3]. Regulated Electric and Gas Utilities are companies whose predominant[4] business is the sale of electricity and/or gas or related services under a rate-regulated framework, in most cases to retail customers. Also included under this methodology are rate-regulated utilities that own generating assets as any material part of their business, utilities whose charges or bills to customers include a meaningful component related to the electric or gas commodity, utilities whose rates are regulated at a sub-sovereign level (e.g. by provinces, states or municipalities), and companies providing an independent system operator function to an electric grid. Companies rated under this methodology are primarily rate-regulated monopolies or, in certain circumstances, companies that may not be outright monopolies but where government regulation effectively sets prices and limits competition.

This rating methodology covers regulated electric and gas utilities worldwide. These companies are engaged in the production, transmission, coordination, distribution and/or sale of electricity and/or natural gas, and they are either investor owned companies, commercially oriented government owned companies or, in the case of independent system operators, not-for-profit or similar entities. As detailed in Appendix C, this methodology covers a wide variety of companies active in the sector, including vertically integrated utilities, transmission and distribution utilities with retail customers and/or sub-sovereign regulation, local gas distribution utility companies (LDCs), independent system operators, and regulated generation companies. These companies may be operating companies or holding companies.

An over-arching consideration for regulated utilities is the regulatory environment in which they operate. While regulation is also a key consideration for networks, a utility's regulatory environment is in comparison often more dynamic and more subject to political intervention. The direct relationship that a regulated utility has with the retail customer, including billing for electric or gas supply that has substantial price volatility, can lead to a more politically charged rate-setting environment. Similarly, regulation at the sub-sovereign level is often more accessible for participation by interveners, including disaffected customers and the politicians who want their votes. Our views of regulatory environments evolve over time in accordance with our observations of regulatory, political, and judicial events that affect issuers in the sector.

This methodology pertains to regulated electric and gas utilities and excludes the following types of issuers, which are covered by separate rating methodologies: Regulated Networks, Unregulated Utilities and Power Companies, Public Power Utilities, Municipal Joint Action Agencies, Electric Cooperatives, Regulated Water Companies and Natural Gas Pipelines.[5]

The Regulated Electric and Gas Utility sector is predominantly investment grade, reflecting the stability generally conferred by regulation that typically sets prices and also limits competition, such that defaults have been lower than in many other non-financial corporate sectors. However, the nature of regulation can

[2] Companies in many industries are regulated. We use the term rate-regulated to distinguish companies whose rates (by which we also mean tariffs or revenues in general) are set by regulators.

[3] Regulated Electric and Gas Networks are companies whose predominant business is purely the transmission and/or distribution of electricity and/or natural gas without involvement in the procurement or sale of electricity and/or gas; whose charges to customers thus do not include a meaningful commodity cost component; which sell mainly (or in many cases exclusively) to non-retail customers; and which are rate-regulated under a national framework.

[4] We generally consider a company to be predominantly a regulated electric and gas utility when a majority of its cash flows, prospectively and on a sustained basis, are derived from regulated electric and gas utility businesses. Since cash flows can be volatile (such that a company might have a majority of utility cash flows simply due to a cyclical downturn in its non-utility businesses), we may also consider the breakdown of assets and/or debt of a company to determine which business is predominant.

[5] A link to credit rating methodologies covering these and other sectors can be found in the Related Research section of this report.

vary significantly from jurisdiction to jurisdiction. Most issuers at the lower end of the ratings spectrum operate in challenging regulatory environments.

About this Rating Methodology

This report explains the rating methodology for regulated electric and gas utilities in six sections, which are summarized as follows:

1. Identification and Discussion of the Rating Factors in the Grid

The grid in this rating methodology focuses on four rating factors. The four factors are comprised of sub-factors that provide further detail:

Factor / Sub-Factor Weighting - Regulated Utilities

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Framework	25%	Legislative and Judicial Underpinnings of the Regulatory Framework	12.5%
		Consistency and Predictability of Regulation	12.5%
Ability to Recover Costs and Earn Returns	25%	Timeliness of Recovery of Operating and Capital Costs	12.5%
		Sufficiency of Rates and Returns	12.5%
Diversification	10%	Market Position	5%*
		Generation and Fuel Diversity	5%**
Financial Strength, Key Financial Metrics	40%		
		CFO pre-WC + Interest / Interest	7.5%
		CFO pre-WC / Debt	15.0%
		CFO pre-WC – Dividends / Debt	10.0%
		Debt/Capitalization	7.5%
Total	100%		100%
Notching Adjustment			
Holding Company Structural Subordination			0 to -3

*10% weight for issuers that lack generation; **0% weight for issuers that lack generation

2. Measurement or Estimation of Factors in the Grid

We explain our general approach for scoring each grid factor and show the weights used in the grid. We also provide a rationale for why each of these grid components is meaningful as a credit indicator. The information used in assessing the sub-factors is generally found in or calculated from information in company financial statements, derived from other observations or estimated by our analysts.[6] All of the quantitative credit metrics incorporate Moody's standard adjustments to income statement, cash flow statement and balance sheet amounts for restructuring, impairment, off-balance sheet accounts, receivable securitization programs, under-funded pension obligations, and recurring operating leases.[7]

6 For definitions of our most common ratio terms, please see "Moody's Basic Definitions for Credit Statistics, User's Guide," a link to which may be found in the Related Research section of this report.

7 Our standard adjustments are described in "Financial Statement Adjustments in the Analysis of Non-Financial Corporations". A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of a company's performance as well as for peer comparisons. We utilize historical data (in most cases, an average of the last three years of reported results) in the rating grid. However, the factors in the grid can be assessed using various time periods. For example, rating committees may find it analytically useful to examine both historic and expected future performance for periods of several years or more, or for individual twelve month periods.

3. Mapping Factors to the Rating Categories

After estimating or calculating each sub-factor, the outcomes for each of the sub-factors are mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, B, or Caa).

4. Assumptions, Limitations and Rating Considerations Not Included in the Grid

This section discusses limitations in the use of the grid to map against actual ratings, some of the additional factors that are not included in the grid but can be important in determining ratings, and limitations and assumptions that pertain to the overall rating methodology.

5. Determining the Overall Grid-Indicated Rating[8]

To determine the overall grid-indicated rating, we convert each of the sub-factor ratings into a numeric value based upon the scale below.

Aaa	Aa	A	Baa	Ba	B	Caa	Ca
1	3	6	9	12	15	18	20

The numerical score for each sub-factor is multiplied by the weight for that sub-factor with the results then summed to produce a composite weighted-factor score. The composite weighted factor score is then mapped back to an alphanumeric rating based on the ranges in the table below.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Aaa	$x < 1.5$
Aa1	$1.5 \leq x < 2.5$
Aa2	$2.5 \leq x < 3.5$
Aa3	$3.5 \leq x < 4.5$
A1	$4.5 \leq x < 5.5$
A2	$5.5 \leq x < 6.5$
A3	$6.5 \leq x < 7.5$
Baa1	$7.5 \leq x < 8.5$
Baa2	$8.5 \leq x < 9.5$
Baa3	$9.5 \leq x < 10.5$

8 In general, the grid-indicated rating is oriented to the Corporate Family Rating (CFR) for speculative-grade issuers and the senior unsecured rating for investment-grade issuers. For issuers that benefit from ratings uplift due to parental support, government ownership or other institutional support, the grid-indicated rating is oriented to the baseline credit assessment. For an explanation of baseline credit assessment, please refer to our rating methodology on government-related issuers. Individual debt instrument ratings also factor in decisions on notching for seniority level and collateral. The documents that provide broad guidance for these notching decisions are our rating methodologies on loss given default for speculative grade non-financial companies and for aligning corporate instrument ratings based on differences in security and priority of claim. The link to these and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5
Caa1	16.5 ≤ x < 17.5
Caa2	17.5 ≤ x < 18.5
Caa3	18.5 ≤ x < 19.5
Ca	x ≥ 19.5

For example, an issuer with a composite weighted factor score of 11.7 would have a Ba2 grid-indicated rating.

6. Appendices

The Appendices present a full grid and provide additional commentary and insights on our view of credit risks in this industry.

Discussion of the Grid Factors

Our analysis of electric and gas utilities focuses on four broad factors:

» Regulatory Framework

» Ability to Recover Costs and Earn Returns

» Diversification

» Financial Strength

There is also a notching factor for holding company structural subordination.

Factor 1: Regulatory Framework (25%)

Why It Matters

For rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations. The regulatory environment is comprised of two rating factors - the Regulatory Framework and its corollary factor, the Ability to Recover Costs and Earn Returns. Broadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation. The Ability to Recover Costs and Earn Returns relates more directly to the actual decisions, including their timeliness and the rate-setting outcomes.

Utility rates[9] are set in a political/regulatory process rather than a competitive or free-market process; thus, the Regulatory Framework is a key determinant of the success of utility. The Regulatory Framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary that interprets the laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. In many cases, utilities have experienced credit stress or default primarily or at least secondarily because of a break-down or obstacle in the Regulatory Framework – for instance, laws that prohibited regulators from including investments in uncompleted power plants or plants not deemed "used and useful" in rates, or a disagreement about rate-making that could not be resolved until after the utility had defaulted on its debts.

How We Assess Legislative and Judicial Underpinnings of the Regulatory Framework for the Grid

For this sub-factor, we consider the scope, clarity, transparency, supportiveness and granularity of utility legislation, decrees, and rules as they apply to the issuer. We also consider the strength of the regulator's authority over rate-making and other regulatory issues affecting the utility, the effectiveness of the judiciary or other independent body in arbitrating disputes in a disinterested manner, and whether the utility's monopoly has meaningful or growing carve-outs. In addition, we look at how well developed the framework is – both how fully fleshed out the rules and regulations are and how well tested it is – the extent to which regulatory or judicial decisions have created a body of precedent that will help determine future rate-making. Since the focus of our scoring is on each issuer, we consider how effective the utility is in navigating the regulatory framework – both the utility's ability to shape the framework and adapt to it.

A utility operating in a regulatory framework that is characterized by legislation that is credit supportive of utilities and eliminates doubt by prescribing many of the procedures that the regulators will use in determining fair rates (which legislation may show evidence of being responsive to the needs of the utility in general or specific ways), a long history of transparent rate-setting, and a judiciary that has provided ample precedent by impartially adjudicating disagreements in a manner that addresses ambiguities in the laws and rules will receive higher scores in the Legislative and Judicial Underpinnings sub-factor. A utility operating in a regulatory framework that, by statute or practice, allows the regulator to arbitrarily prevent the utility from recovering its costs or earning a reasonable return on prudently incurred investments, or where regulatory decisions may be reversed by politicians seeking to enhance their populist appeal will receive a much lower score.

In general, we view national utility regulation as being less liable to political intervention than regulation by state, provincial or municipal entities, so the very highest scoring in this sub-factor is reserved for this category. However, we acknowledge that states and provinces in some countries may be larger than small nations, such that their regulators may be equally "above-the-fray" in terms of impartial and technically-oriented rate setting, and very high scoring may be appropriate.

[9] In jurisdictions where utility revenues include material government subsidy payments, we consider utility rates to be inclusive of these payments, and we thus evaluate sub-factors 1a, 1b, 2a and 2b in light of both rates and material subsidy payments. For example, we would consider the legal and judicial underpinnings and consistency and predictability of subsidies as well as rates.

The relevant judicial system can be a major factor in the regulatory framework. This is particularly true in litigious societies like the United States, where disagreements between the utility and its state or municipal regulator may eventually be adjudicated in federal district courts or even by the US Supreme Court. In addition, bankruptcy proceedings in the US take place in federal courts, which have at times been able to impose rate settlement agreements on state or municipal regulators. As a result, the range of decisions available to state regulators may be effectively circumscribed by court precedent at the state or federal level, which we generally view as favorable for the credit- supportiveness of the regulatory framework.

Electric and gas utilities are generally presumed to have a strong monopoly that will continue into the foreseeable future, and this expectation has allowed these companies to have greater leverage than companies in other sectors with similar ratings. Thus, the existence of a monopoly in itself is unlikely to be a driver of strong scoring in this sub-factor. On the other hand, a strong challenge to the monopoly could cause lower scoring, because the utility can only recover its costs and investments and service its debt if customers purchase its services. There have some instances of incursions into utilities' monopoly, including municipalization, self-generation, distributed generation with net metering, or unauthorized use (beyond the level for which the utility receives compensation in rates). Incursions that are growing significantly or having a meaningful impact on rates for customers that remain with the utility could have a negative impact on scoring of this sub-factor and on factor 2 - Ability to Recover Costs and Earn Returns.

The scoring of this sub-factor may not be the same for every utility in a particular jurisdiction. We have observed that some utilities appear to have greater sway over the relevant utility legislation and promulgation of rules than other utilities – even those in the same jurisdiction. The content and tone of publicly filed documents and regulatory decisions sometimes indicates that the management team at one utility has better responsiveness to and credibility with its regulators or legislators than the management at another utility.

While the underpinnings to the regulatory framework tend to change relatively slowly, they do evolve, and our factor scoring will seek to reflect that evolution. For instance, a new framework will typically become tested over time as regulatory decisions are issued, or perhaps litigated, thereby setting a body of precedent. Utilities may seek changes to laws in order to permit them to securitize certain costs or collect interim rates, or a jurisdiction in which rates were previously recovered primarily in base rate proceedings may institute riders and trackers. These changes would likely impact scoring of sub-factor 2b - Timeliness of Recovery of Operating and Capital Costs, but they may also be sufficiently significant to indicate a change in the regulatory underpinnings. On the negative side, a judiciary that had formerly been independent may start to issue decisions that indicate it is conforming its decisions to the expectations of an executive branch that wants to mandate lower rates.

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1) within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor-unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

How We Assess Consistency and Predictability of Regulation for the Grid

For the Consistency and Predictability sub-factor, we consider the track record of regulatory decisions in terms of consistency, predictability and supportiveness. We evaluate the utility's interactions in the regulatory process as well as the overall stance of the regulator toward the utility.

In most jurisdictions, the laws and rules seek to make rate-setting a primarily technical process that examines costs the utility incurs and the returns on investments the utility needs to earn so it can make investments that are required to build and maintain the utility infrastructure - power plants, electric transmission and distribution systems, and/or natural gas distribution systems. When the process remains technical and transparent such that regulators can support the financial health of the utility while balancing their public duty to assure that reliable service is provided at a reasonable cost, and when the utility is able to align itself with the policy initiatives of the governing jurisdiction, the utility will receive higher scores in this sub-factor. When the process includes substantial political intervention, which could take the form of legislators or other government officials publically second- guessing regulators, dismissing regulators who have approved unpopular rate increases, or preventing the implementation of rate increases, or when regulators ignore the laws/rules to deliver an outcome that appears more politically motivated, the utility will receive lower scores in this sub-factor.

As with the prior sub-factor, we may score different utilities in the same jurisdiction differently, based on outcomes that are more or less supportive of credit quality over a period of time. We have observed that some utilities are better able to meet the expectations of their customers and regulators, whether through better service, greater reliability, more stable rates or simply more effective regulatory outreach and communication. These utilities typically receive more consistent and credit supportive outcomes, so they will score higher in this sub-factor. Conversely, if a utility has multiple rapid rate increases, chooses to submit major rate increase requests during a sensitive election cycle or a severe economic downturn, has chronic customer service issues, is viewed as frequently providing incomplete information to regulators, or is tone deaf to the priorities of regulators and politicians, it may receive less consistent and supportive outcomes and thus score lower in this sub-factor.

In scoring this sub-factor, we will primarily evaluate the actions of regulators, politicians and jurists rather than their words. Nonetheless, words matter when they are an indication of future action. We seek to differentiate between political rhetoric that is perhaps oriented toward gaining attention for the viewpoint of the speaker and rhetoric that is indicative of future actions and trends in decision- making.

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2: Ability to Recover Costs and Earn Returns (25%)

Why It Matters

This rating factor examines the ability of a utility to recover its costs and earn a return over a period of time, including during differing market and economic conditions. While the Regulatory Framework looks at the transparency and predictability of the rules that govern the decision-making process with respect to utilities, the Ability to Recover Costs and Earn Returns evaluates the regulatory elements that directly impact the ability of the utility to generate cash flow and service its debt over time. The ability to recover prudently incurred costs on a timely basis and to attract debt and equity capital are crucial credit considerations. The inability to recover costs, for instance if fuel or purchased power costs ballooned during a rate freeze period, has been one of the greatest drivers of financial stress in this sector, as well as the cause of some utility defaults. In a sector that is typically free cash flow negative (due to large capital expenditures and dividends) and that routinely needs to refinance very large maturities of long-term debt, investor concerns about a lack of timely cost recovery or the sufficiency of rates can, in an extreme scenario, strain access to capital markets and potentially lead to insolvency of the utility (as was the case when "used and useful" requirements threatened some utilities that experienced years of delay in completing nuclear power plants in the 1980s). While our scoring for the Ability to Recover Costs and Earn Returns may primarily be influenced by our assessment of the regulatory relationship, it can also be highly impacted by the management and business decisions of the utility.

How We Assess Ability to Recover Costs and Earn Returns

The timeliness and sufficiency of rates are scored as separate sub-factors; however, they are interrelated. Timeliness can have an impact on our view of what constitutes sufficient returns, because a strong assurance of timely cost recovery reduces risk. Conversely, utilities may have a strong assurance that they will earn a full return on certain deferred costs until they are able to collect them, or their generally strong returns may allow them to weather some rate lag on recovery of construction-related capital expenditures. The timeliness of cost recovery is particularly important in a period of rapidly rising costs. During the past five years, utilities have benefitted from low interest rates and generally decreasing fuel costs and purchased power costs, but these market conditions could easily reverse. For example, fuel is a large component of total costs for vertically integrated utilities and for natural gas utilities, and fuel prices are highly volatile, so the timeliness of fuel and purchased power cost recovery is especially important.

While Factors 1 and 2 are closely inter-related, scoring of these factors will not necessarily be the same. We have observed jurisdictions where the Regulatory Framework caused considerable credit concerns – perhaps it was untested or going through a transition to de-regulation, but where the track record of rate case outcomes was quite positive, leading to a higher score in the Ability to Recover Costs and Earn Returns. Conversely, there have been instances of strong Legislative and Judicial Underpinnings of the Regulatory Framework where the commission has ignored the framework (which would affect Consistency and Predictability of Regulation as well as Ability to Recover Costs and Earn Returns) or has used extraordinary measures to prevent or defer an increase that might have been justifiable from a cost perspective but would have caused rate shock.

One might surmise that Factors 2 and 4 should be strongly correlated, since a good Ability to Recover Costs and Earn Returns would normally lead to good financial metrics. However, the scoring for the Ability to Recover Costs and Earn Returns sub-factor places more emphasis on our expectation of timeliness and sufficiency of rates over time; whereas financial metrics may be impacted by one-time events, market conditions or construction cycles - trends that we believe could normalize or even reverse.

How We Assess Timeliness of Recovery of Operating and Capital Costs for the Grid

The criteria we consider include provisions and cost recovery mechanisms for operating costs, mechanisms that allow actual operating and/or capital expenditures to be trued-up periodically into rates without having to file a rate case (this may include formula rates, rider and trackers, or the ability to periodically adjust rates for construction work in progress) as well as the process and timeframe of general tariff/base rate cases – those that are fully reviewed by the regulator, generally in a public format that includes testimony of the utility and other stakeholders and interest groups. We also look at the track record of the utility and regulator for timeliness. For instance, having a formula rate plan is positive, but if the actual process has included reviews that are delayed for long periods, it may dampen the benefit to the utility. In addition, we seek to estimate the lag between the time that a utility incurs a major construction expenditures and the time that the utility will start to recover and/or earn a return on that expenditure.

How We Assess Sufficiency of Rates and Returns for the Grid

The criteria we consider include statutory protections that assure full cost recovery and a reasonable return for the utility on its investments, the regulatory mechanisms used to determine what a reasonable return should be, and the track record of the utility in actually recovering costs and earning returns. We examine outcomes of rate cases/tariff reviews and compare them to the request submitted by the utility, to prior rate cases/tariff reviews for the same utility and to recent rate/tariff decisions for a peer group of comparable utilities. In this context, comparable utilities are typically utilities in the same or similar jurisdiction. In cases where the utility is unique or nearly unique in its jurisdiction, comparison will be made to other peers with an adjustment for local differences, including prevailing rates of interest and returns on capital, as well as the timeliness of rate-setting. We look at regulatory disallowances of costs or investments, with a focus on their financial severity and also on the reasons given by the regulator, in order to assess the likelihood that such disallowances will be repeated in the future.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward-looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward-looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non-refundable interim rates) can be collected, and permit inclusion of important forward-looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa	
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.	

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa	
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.	

Factor 3: Diversification (10%)

Why It Matters

Diversification of overall business operations helps to mitigate the risk that economic cycles, material changes in a single regulatory regime or commodity price movements will have a severe impact on cash flow and credit quality of a utility. While utilities' sales volumes have lower exposure to economic recessions than many non-financial corporate issuers, some sales components, including industrial sales, are directly affected by economic trends that cause lower production and/or plant closures. In addition, economic activity plays a role in the rate of customer growth in the service territory and (absent energy efficiency and conservation) can often impact usage per customer. The economic strength or weakness of the service territory can affect the political and regulatory environment for rate increase requests by the utility. For utilities in areas prone to severe storms and other natural disasters, the utility's geographic diversity or concentration can be a key determinant for creditworthiness.

Diversity among regulatory regimes can mitigate the impact of a single unfavorable decision affecting one part of the utility's footprint.

For utilities with electric generation, fuel source diversity can mitigate the impact (to the utility and to its rate-payers) of changes in commodity prices, hydrology and water flow, and environmental or other regulations affecting plant operations and economics. We have observed that utilities' regulatory environments are most likely to become unfavorable during periods of rapid rate increases (which are more important than absolute rate levels) and that fuel diversity leads to more stable rates over time.

For that reason, fuel diversity can be important even if fuel and purchased power expenses are an automatic pass-through to the utility's ratepayers. Changes in environmental, safety and other regulations have caused vulnerabilities for certain technologies and fuel sources during the past five years. These vulnerabilities have varied widely in different countries and have changed over time.

How We Assess Market Position for the Grid

Market position is comprised primarily of the economic diversity of the utility's service territory and the diversity of its regulatory regimes. We also consider the diversity of utility operations (e.g., regulated electric, gas, water, steam) when there are material operations in more than one area.

Economic diversity is a typically a function of the population, size and breadth of the territory and the businesses that drive its GDP and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth, we consider the number of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry. In our assessment, we may consider various information sources. For example, in the US, information sources on the diversity and vitality of economies of individual states and metropolitan areas may include Moody's Economy.com. We also look at the mix of the utility's sales volumes among customer types, as well as the track record of volume sales and any notable payment patterns during economic cycles. For diversity of regulatory regimes, we typically look at the number of regulators and the percentages of revenues and utility assets that are under the purview of each. While the highest scores in the Market Position sub-factor are reserved for issuers regulated in multiple jurisdictions, when there is only one regulator, we make a differentiation of regimes perceived as having lower or higher volatility.

Issuers with multiple supportive regulatory jurisdictions, a balanced sales mix among residential, commercial, industrial and governmental customers in a large service territory with a robust and diverse economy will generally score higher in this sub-factor. An issuer with a small service territory economy that has a high dependence on one or two sectors, especially highly cyclical industries, will generally score lower in this sub-factor, as will issuers with meaningful exposure to economic dislocations caused by natural disasters.

For issuers that are vertically integrated utilities having a meaningful amount of generation, this sub- factor has a weighting of 5%. For electric transmission and distribution utilities without meaningful generation and for natural gas local distribution companies, this sub-factor has a weighting of 10%.

How We Assess Generation and Fuel Diversity for the Grid

Criteria include the fuel type of the issuer's generation and important power purchase agreements, the ability of the issuer economically to shift its generation and power purchases when there are changes in fuel prices, the degree to which the utility and its rate-payers are exposed to or insulated from changes in commodity prices, and exposure to Challenged Source and Threatened Sources (see the explanations for how we generally characterize these generation sources in the table below). A regulated utility's capacity mix may not in itself be an indication of fuel diversity or the ability to shift fuels, since utilities may keep old and inefficient plants (e.g., natural gas boilers) to serve peak load. For this reason, we do not incorporate set percentages reflecting an "ideal" or "sub-par" mix for capacity or even generation. In addition to looking at a utility's generation mix to evaluate fuel diversity, we consider the efficiency of the utility's plants, their placement on the regional dispatch curve, and the demonstrated ability/inability of the utility to shift its generation mix in accordance with changing commodity prices.

Issuers having a balanced mix of hydro, coal, natural gas, nuclear and renewable energy as well as low exposure to challenged and threatened sources of generation will score more highly in this sub-factor. Issuers that have concentration in one or two sources of generation, especially if they are threatened or challenged sources, will incur lower scores.

In evaluating an issuer's degree of exposure to challenged and threatened sources, we will consider not only the existence of those plants in the utility's portfolio, but also the relevant factors that will determine the impact on the utility and on its rate-payers. For instance, an issuer that has a fairly high percentage of its generation from challenged sources could be evaluated very differently if its peer utilities face the same magnitude of those issues than if its peers have no exposure to challenged or threatened sources. In evaluating threatened sources, we consider the utility's progress in its plan to replace those sources, its reserve margin, the availability of purchased power capacity in the region, and the overall impact of the replacement plan on the issuer's rates relative to its peer group. Especially if there are no peers in the same jurisdiction, we also examine the extent to which the utility's generation resources plan is aligned with the relevant government's fuel/energy policy.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5.00% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5.00% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definiitons
Market Position	5.00% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.

Generation and Fuel Diversity	5.00% **	Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength (40%)

Why It Matters

Electric and gas utilities are regulated, asset-based businesses characterized by large investments in long-lived property, plant and equipment. Financial strength, including the ability to service debt and provide a return to shareholders, is necessary for a utility to attract capital at a reasonable cost in order to invest in its generation, transmission and distribution assets, so that the utility can fulfill its service obligations at a reasonable cost to rate-payers.

How We Assess It for the Grid

In comparison to companies in other non-financial corporate sectors, the financial statements of regulated electric and gas utilities have certain unique aspects that impact financial analysis, which is further complicated by disparate treatment of certain elements under US Generally Accepted Accounting Principles (GAAP) versus International Financial Reporting Standards (IFRS). Regulatory accounting may permit utilities to defer certain costs (thereby creating regulatory assets) that a non- utility corporate entity would have to expense. For instance, a regulated utility may be able to defer a substantial portion of costs related to recovery from a storm based on the general regulatory framework for those expenses, even if the utility does not have a specific order to collect the expenses from ratepayers over a set period of time. A regulated utility may be able to accrue and defer a return on equity (in addition to capitalizing interest) for construction-work-in-progress for an approved project based on the assumption that it will be able to collect that deferred equity return once the asset comes into service. For this reason, we focus more on a utility's cash flow than on its reported net income.

Conversely, utilities may collect certain costs in rates well ahead of the time they must be paid (for instance, pension costs), thereby creating regulatory liabilities. Many of our metrics focus on Cash Flow from Operations Before Changes in Working Capital (CFO Pre-WC) because, unlike Funds from Operations (FFO), it captures the changes in long-term regulatory assets and liabilities.

However, under IFRS the two measures are essentially the same. In general, we view changes in working capital as less important in utility financial analysis because they are often either seasonal (for example, power demand is generally greatest in the summer) or caused by changes in fuel prices that are typically a relatively automatic pass-through to the customer. We will nonetheless examine the impact of working capital changes in analyzing a utility's liquidity (see Other Rating Considerations – Liquidity).

Given the long-term nature of utility assets and the often lumpy nature of their capital expenditures, it is important to analyze both a utility's historical financial performance as well as its prospective future performance, which may be different from backward-looking measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance. Multi-year periods are usually more representative of credit quality because utilities can experience swings in cash flows from one-time events, including such items as rate refunds, storm cost deferrals that create a regulatory asset, or securitization proceeds that reduce a regulatory asset. Nonetheless, we also look at trends in metrics for individual periods, which may influence our view of future performance and ratings.

For this scoring grid, we have identified four key ratios that we consider the most consistently useful in the analysis of regulated electric and gas utilities. However, no single financial ratio can adequately convey the relative credit strength of these highly diverse companies. Our ratings consider the overall financial strength of a company, and in individual cases other financial indicators may also play an important role.

CFO Pre-Working Capital Plus Interest/Interest or Cash Flow Interest Coverage

The cash flow interest coverage ratio is an indicator for a utility's ability to cover the cost of its borrowed capital. The numerator in the ratio calculation is the sum of CFO Pre-WC and interest expense, and the denominator is interest expense.

CFO Pre-Working Capital / Debt

This important metric is an indicator for the cash generating ability of a utility compared to its total debt. The numerator in the ratio calculation is CFO Pre-WC, and the denominator is total debt.

CFO Pre-Working Capital Minus Dividends / Debt

This ratio is an indicator for financial leverage as well as an indicator of the strength of a utility's cash flow after dividend payments are made. Dividend obligations of utilities are often substantial, quasi- permanent outflows that can affect the ability of a utility to cover its debt obligations, and this ratio can also provide insight into the financial policies of a utility or utility holding company. The higher the level of retained cash flow relative to a utility's debt, the more cash the utility has to support its capital expenditure program. The numerator of this ratio is CFO Pre-WC minus dividends, and the denominator is total debt.

Debt/Capitalization

This ratio is a traditional measure of balance sheet leverage. The numerator is total debt and the denominator is total capitalization. All of our ratios are calculated in accordance with our standard adjustments[10], but we note that our definition of total capitalization includes deferred taxes in addition to total debt, preferred stock, other hybrid securities, and common equity. Since the presence or absence of deferred taxes is a function of national tax policy, comparing utilities using this ratio may be more meaningful among utilities in the same country or in countries with similar tax policies. High debt levels in comparison to capitalization can indicate higher interest obligations, can limit the ability of a utility to raise additional financing if needed, and can lead to leverage covenant violations in bank credit facilities or other financing agreements[11]. A high ratio may result from a regulatory framework that does not permit a robust cushion of equity in the capital structure, or from a material write-off of an asset, which may not have impacted current period cash flows but could affect future period cash flows relative to debt.

There are two sets of thresholds for three of these ratios based on the level of the issuer's business risk – the Standard Grid and the Lower Business Risk (LBR) Grid. In our view, the different types of utility entities covered under this methodology (as described in Appendix E) have different levels of business risk.

Generation utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays.

Other types of utilities may have lower business risk, such that we believe that they are most appropriately assessed using the LBR Grid, due to factors that could include a generally greater transfer of risk to customers, very strong insulation from exposure to commodity price movements, good protection from volumetric risks, fairly limited capex needs and low exposure to storms, major accidents and natural

10 In certain circumstances, analysts may also apply specific adjustments.

11 We also examine debt/capitalization ratios as defined in applicable covenants (which typically exclude deferred taxes from capitalization) relative to the covenant threshold level.

disasters. For instance, we tend to view many US natural gas local distribution companies (LDCs) and certain US electric transmission and distribution companies (T&Ds, which lack generation but generally retain some procurement responsibilities for customers), as typically having a lower business risk profile than their vertically integrated peers. In cases of T&Ds that we do not view as having materially lower risk than their vertically integrated peers, we will apply the Standard grid. This could result from a regulatory framework that exposes them to energy supply risk, large capital expenditures for required maintenance or upgrades, a heightened degree of exposure to catastrophic storm damage, or increased regulatory scrutiny due to poor reliability, or other considerations. The Standard Grid will also apply to LDCs that in our view do not have materially lower risk; for instance, due to their ownership of high pressure pipes or older systems requiring extensive gas main replacements, where gas commodity costs are not fully recovered in a reasonably contemporaneous manner, or where the LDC is not well insulated from declining volumes.

The four key ratios, their weighting in the grid, and the Standard and LBR scoring thresholds are detailed in the following table.

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.50%		≥ 8.0x	6.0x - 8.0x	4.5x - 6.0x	3.0x - 4.5x	2.0x - 3.0x	1.0x - 2.0x	< 1.0x
CFO pre-WC / Debt	15.00%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10.00%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
Debt / Capitalization	7.50%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Notching for Structural Subordination of Holding Companies

Why It Matters

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries that are structured as advances, debt, or even hybrid securities.

Most HoldCos present their financial statements on a consolidated basis that blurs legal considerations about priority of creditors based on the legal structure of the family, and grid scoring is thus based on consolidated ratios. However, HoldCo creditors typically have a secondary claim on the group's cash flows and assets after OpCo creditors. We refer to this as structural subordination, because it is the corporate legal structure, rather than specific subordination provisions, that causes creditors at each of the utility and non-utility subsidiaries to have a more direct claim on the cash flows and assets of their respective OpCo obligors. By contrast, the debt of the HoldCo is typically serviced primarily by dividends that are upstreamed by the OpCos[12]. Under normal circumstances, these dividends are made from net income, after payment of the OpCo's interest and preferred dividends. In most non- financial corporate sectors where cash often moves freely between the entities in a single issuer family, this distinction may have less of an impact. However, in the regulated utility sector, barriers to movement of cash among companies in the corporate family can be much more restrictive, depending on the regulatory framework. These barriers can lead to significantly different probabilities of default for HoldCos and OpCos. Structural subordination also affects loss given default. Under most default[13] scenarios, an OpCo's creditors will be satisfied from the value residing at that OpCo before any of the OpCo's assets can be used to satisfy claims of the HoldCo's creditors. The prevalence of debt issuance at the OpCo level is another reason that structural subordination is usually a more serious concern in the utility sector than for investment grade issuers in other non-financial corporate sectors.

The grids for factors 1-4 are primarily oriented to OpCos (and to some degree for HoldCos with minimal current structural subordination; for example, there is no current structural subordination to debt at the operating company if all of the utility family's debt and preferred stock is issued at the HoldCo level, although there is structural subordination to other liabilities at the OpCo level). The additional risk from structural subordination is addressed via a notching adjustment to bring grid outcomes (on average) closer to the actual ratings of HoldCos.

How We Assess It

Grid-indicated ratings of holding companies may be notched down based on structural subordination. The risk factors and mitigants that impact structural subordination are varied and can be present in different combinations, such that a formulaic approach is not practical and case-by-case analyst judgment of the interaction of all pertinent factors that may increase or decrease its importance to the credit risk of an issuer are essential.

Some of the potentially pertinent factors that could increase the degree and/or impact of structural subordination include the following:

» Regulatory or other barriers to cash movement from OpCos to HoldCo

» Specific ring-fencing provisions

» Strict financial covenants at the OpCo level

» Higher leverage at the OpCo level

» Higher leverage at the HoldCo level[14]

» Significant dividend limitations or potential limitations at an important OpCo

» HoldCo exposure to subsidiaries with high business risk or volatile cash flows

Strained liquidity at the HoldCo level

» The group's investment program is primarily in businesses that are higher risk or new to the group

Some of the potentially mitigating factors that could decrease the degree and/or impact of structural subordination include the following:

[12] The HoldCo and OpCo may also have intercompany agreements, including tax sharing agreements, that can be another source of cash to the HoldCo.

[13] Actual priority in a default scenario will be determined by many factors, including the corporate and bankruptcy laws of the jurisdiction, the asset value of each OpCo, specific financing terms, inter-relationships among members of the family, etc.

[14] While higher leverage at the HoldCo does not increase structural subordination per se, it exacerbates the impact of any structural subordination that exists

» Substantial diversity in cash flows from a variety of utility OpCos

» Meaningful dividends to HoldCo from unlevered utility OpCos

» Dependable, meaningful dividends to HoldCo from non-utility OpCos

» The group's investment program is primarily in strong utility businesses

» Inter-company guarantees - however, in many jurisdictions the value of an upstream guarantee may be limited by certain factors, including by the value that the OpCo received in exchange for granting the guarantee

Notching for structural subordination within the grid may range from 0 to negative 3 notches. Instances of extreme structural subordination are relatively rare, so the grid convention does not accommodate wider differences, although in the instances where we believe it is present, actual ratings do reflect the full impact of structural subordination.

A related issue is the relationship of ratings within a utility family with multiple operating companies, and sometimes intermediate holding companies. Some of the key issues are the same, such as the relative amounts of debt at the holding company level compared to the operating company level (or at one OpCo relative to another), and the degree to which operating companies have credit insulation due to regulation or other protective factors. Appendix B has additional insights on ratings within a utility family.

Rating Methodology Assumptions, Limitations, and Other Rating Considerations

The grid in this rating methodology represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that might enable the grid to map more closely to actual ratings. Accordingly, the four rating factors and the notching factor in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in the regulated electric and gas utility sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used in the grid in this document is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we can't disclose. In other cases, we estimate future results based upon past performance, industry trends, competitor actions or other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

Assumptions that may cause our forward-looking expectations to be incorrect include unanticipated changes in any of the following factors: the macroeconomic environment and general financial market conditions, industry competition, disruptive technology, regulatory and legal actions.

Key rating assumptions that apply in this sector include our view that sovereign credit risk is strongly correlated with that of other domestic issuers, that legal priority of claim affects average recovery on different classes of debt, sufficiently to generally warrant differences in ratings for different debt classes of the same issuer, and the assumption that lack of access to liquidity is a strong driver of credit risk.

In choosing metrics for this rating methodology grid, we did not explicitly include certain important factors that are common to all companies in any industry such as the quality and experience of management, assessments of corporate governance and the quality of financial reporting and information disclosure. Therefore ranking these factors by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that have a meaningful effect in differentiating credit quality only in some cases, but not all. Such factors include financial controls, exposure to uncertain licensing regimes and possible government interference in some countries.

Regulatory, litigation, liquidity, technology and reputational risk as well as changes to consumer and business spending patterns, competitor strategies and macroeconomic trends also affect ratings. While these are important considerations, it is not possible precisely to express these in the rating methodology grid without making the grid excessively complex and significantly less transparent.

Ratings may also reflect circumstances in which the weighting of a particular factor will be substantially different from the weighting suggested by the grid.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the grid. For example, liquidity is a consideration frequently critical to ratings and which may not, in other circumstances, have a substantial impact in discriminating between two issuers with a similar credit profile. As an example of the limitations, ratings can be heavily affected by extremely weak liquidity that magnifies default risk. However, two identical companies might be rated the same if their only differentiating feature is that one has a good liquidity position while the other has an extremely good liquidity position.

Other Rating Considerations

We consider other factors in addition to those discussed in this report, but in most cases understanding the considerations discussed herein should enable a good approximation of our view on the credit quality of companies in the regulated electric and gas utilities sector. Ratings consider our assessment of the quality of management, corporate governance, financial controls, liquidity management, event risk and seasonality. The analysis of these factors remains an integral part of our rating process.

Liquidity and Access to Capital Markets

Liquidity analysis is a key element in the financial analysis of electric and gas utilities, and it encompasses a company's ability to generate cash from internal sources as well as the availability of external sources of financing to supplement these internal sources. Liquidity and access to financing are of particular importance in this sector. Utility assets can often have a very long useful life- 30, 40 or even 60 years is not uncommon, as well as high price tags. Partly as a result of construction cycles, the utility sector has experienced prolonged periods of negative free cash flow – essentially, the sum of its dividends and its capital expenditures for maintenance and growth of its infrastructure frequently exceeds cash from operations, such that a portion of capital expenditures must routinely be debt financed. Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility. Substantial portions of capex are non-discretionary (for example, maintenance, adding customers to the network, or meeting environmental mandates); however, utilities were swift to cut or defer discretionary spending during the 2007-2009 recession. Dividends represent a quasi-permanent outlay, since utilities typically only rarely will cut their dividend. Liquidity is also important to meet maturing obligations, which often occur in large chunks, and to meet collateral calls under any hedging agreements.

Due to the importance of liquidity, incorporating it as a factor with a fixed weighting in the grid would suggest an importance level that is often far different from the actual weight in the rating. In normal circumstances most companies in the sector have good access to liquidity. The industry generally requires, and for the most part has, large, syndicated, multi-year committed credit facilities. In addition, utilities have demonstrated strong access to capital markets, even under difficult conditions. As a result, liquidity generally has not been an issue for most utilities and a utility with very strong liquidity may not warrant a rating distinction compared to a utility with strong liquidity. However, when there is weakness in liquidity or liquidity management, it can be the dominant consideration for ratings.

Our assessment of liquidity for regulated utilities involves an analysis of total sources and uses of cash over the next 12 months or more, as is done for all corporates. Using our financial projections of the utility and our analysis of its available sources of liquidity (including an assessment of the quality and reliability of alternate liquidity such as committed credit facilities), we evaluate how its projected sources of cash (cash from operations, cash on hand and existing committed multi-year credit facilities) compare to its projected uses (including all or most capital expenditures, dividends, maturities of short and long-term debt, our projection of potential liquidity calls on financial hedges, and important issuer-specific items such as special tax payments). We assume no access to capital markets or additional liquidity sources, no renewal of existing credit facilities, and no cut to dividends. We examine a company's liquidity profile under this scenario, its ability to make adjustments to improve its liquidity position, and any dependence on liquidity sources with lower quality and reliability.

Management Quality and Financial Policy

The quality of management is an important factor supporting the credit strength of a regulated utility or utility holding company. Assessing the execution of business plans over time can be helpful in assessing management's business strategies, policies, and philosophies and in evaluating management performance relative to performance of competitors and our projections. A record of consistency provides us with insight into management's likely future performance in stressed situations and can be an indicator of management's tendency to depart significantly from its stated plans and guidelines.

We also assess financial policy (including dividend policy and planned capital expenditures) and how management balances the potentially competing interests of shareholders, fixed income investors and other stakeholders. Dividends and discretionary capital expenditures are the two primary components over which management has the greatest control in the short term. For holding companies, we consider the extent to which management is willing to stretch its payout ratio (through aggressive increases or delays in needed decreases) in order to satisfy common shareholders. For a utility that is a subsidiary of a parent company with several utility subsidiaries, dividends to the parent may be more volatile depending on the cash generation and cash needs of that utility, because parents typically want to assure that each utility maintains the regulatory debt/equity ratio on which its rates have been set. The effect we have observed is that utility subsidiaries often pay higher dividends when they have lower capital needs and lower dividends when they have higher capital expenditures or other cash needs. Any dividend policy that cuts into the regulatory debt/equity ratio is a material credit negative.

Size – Natural Disasters, Customer Concentration and Construction Risks

The size and scale of a regulated utility has generally not been a major determinant of its credit strength in the same way that it has been for most other industrial sectors. While size brings certain economies of scale that can somewhat affect the utility's cost structure and competitiveness, rates are more heavily impacted by costs related to fuel and fixed assets. Particularly in the US, we have not observed material differences in the success of utilities' regulatory outreach based on their size. Smaller utilities have sometimes been better able to focus their attention on meeting the expectations of a single regulator than their multi-state peers.

However, size can be a very important factor in our assessment of certain risks that impact ratings, including exposure to natural disasters, customer concentration (primarily to industrial customers in a single sector) and construction risks associated with large projects. While the grid attempts to incorporate the first two of these into Factor 3, for some issuers these considerations may be sufficiently important that the rating reflects a greater weight for these risks. While construction projects always carry the risk of cost over-runs and delays, these risks are materially heightened for projects that are very large relative to the size of the utility.

Interaction of Utility Ratings with Government Policies and Sovereign Ratings

Compared to most industrial sectors, regulated utilities are more likely to be impacted by government actions. Credit impacts can occur directly through rate regulation, and indirectly through energy, environmental and tax policies. Government actions affect fuel prices, the mix of generating plants, the certainty and timing of revenues and costs, and the likelihood that regulated utilities will experience financial stress. While our evolving view of the impact of such policies and the general economic and financial climate is reflected in ratings for each utility, some considerations do not lend themselves to incorporation in a simple ratings grid.[15]

Diversified Operations at the Utility

A small number of regulated utilities have diversified operations that are segments within the utility company, as opposed to the more common practice of housing such operations in one or more separate affiliates. In general, we will seek to evaluate the other businesses that are material in accordance with the appropriate methodology and the rating will reflect considerations from such methodologies. There may be analytical limitations in evaluating the utility and non-utility businesses when segment financial results are not fully broken out and these may be addressed through estimation based on available information. Since regulated utilities are a relatively low risk business compared to other corporate sectors, in most cases diversified non-utility operations increase the business risk profile of a utility. Reflecting this tendency, we note that assigned ratings are typically lower than grid- indicated ratings for such companies.

Event Risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in an issuer's fundamental creditworthiness. Typical special events include mergers and acquisitions, asset sales, spin-offs, capital restructuring programs, litigation and shareholder distributions.

Corporate Governance

Among the areas of focus in corporate governance are audit committee financial expertise, the incentives created by executive compensation packages, related party transactions, interactions with outside auditors, and ownership structure.

Investment and Acquisition Strategy

In our credit assessment we take into consideration management's investment strategy. Investment strategy is benchmarked with that of the other companies in the rated universe to further verify its consistency. Acquisitions can strengthen a company's business. Our assessment of a company's tolerance for acquisitions at a given rating level takes into consideration (1) management's risk appetite, including the likelihood of further acquisitions over the medium term; (2) share buy-back activity; (3) the company's commitment to specific leverage targets; and (4) the volatility of the underlying businesses, as well as that of the business acquired. Ratings can often hold after acquisitions even if leverage temporarily climbs above normally acceptable ranges. However, this depends on (1) the strategic fit; (2) pro-forma

[15] See also the cross-sector methodology "How Sovereign Credit Quality May Affect Other Ratings." A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

capitalization/leverage following an acquisition; and (3) our confidence that credit metrics will be restored in a relatively short timeframe.

Financial Controls

We rely on the accuracy of audited financial statements to assign and monitor ratings in this sector. Such accuracy is only possible when companies have sufficient internal controls, including centralized operations, the proper tone at the top and consistency in accounting policies and procedures.

Weaknesses in the overall financial reporting processes, financial statement restatements or delays in regulatory filings can be indications of a potential breakdown in internal controls.

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1) within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward- looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor- unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward -looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward- looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non- refundable interim rates) can be collected, and permit inclusion of important forward -looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definitions
Market Position	5% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.
Generation and Fuel Diversity	5% **	Modest diversification in generation and/or fuel sources such that the utility or rate- payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de- activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.5%		≥ 8x	6x - 8x	4.5x - 6x	3x - 4.5x	2x - 3x	1x - 2x	< 1x
CFO pre-WC / Debt	15%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
Debt / Capitalization	7.5%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Appendix B: Approach to Ratings within a Utility Family

Typical Composition of a Utility Family

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. Financing of these entities varies by region, in part due to the regulatory framework. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries or minority interests in other companies. However, in certain cases there may be material operations at the HoldCo level. Financing can occur primarily at the OpCo level, primarily at the HoldCo level, or at both HoldCo and OpCos in varying proportions. When a HoldCo has multiple utility OpCos, they will often be located in different regulatory jurisdictions. A HoldCo may have both levered and unlevered OpCos.

General Approach to a Utility Family

In our analysis, we generally consider the stand-alone credit profile of an OpCo and the credit profile of its ultimate parent HoldCo (and any intermediate HoldCos), as well as the profile of the family as a whole, while acknowledging that these elements can have cross-family credit implications in varying degrees, principally based on the regulatory framework of the OpCos and the financing model (which has often developed in response to the regulatory framework).

In addition to considering individual OpCos under this (or another applicable) methodology, we typically[16] approach a HoldCo rating by assessing the qualitative and quantitative factors in this methodology for the consolidated entity and each of its utility subsidiaries. Ratings of individual entities in the issuer family may be pulled up or down based on the interrelationships among the companies in the family and their relative credit strength.

In considering how closely aligned or how differentiated ratings should be among members of a utility family, we assess a variety of factors, including:

» Regulatory or other barriers to cash movement among OpCos and from OpCos to HoldCo

» Differentiation of the regulatory frameworks of the various OpCos

» Specific ring-fencing provisions at particular OpCos

» Financing arrangements – for instance, each OpCo may have its own financing arrangements, or the sole liquidity facility may be at the parent; there may be a liquidity pool among certain but not all members of the family; certain members of the family may better be able to withstand a temporary hiatus of external liquidity or access to capital markets

» Financial covenants and the extent to which an Event of Default by one OpCo limits availability of liquidity to another member of the family

» The extent to which higher leverage at one entity increases default risk for other members of the family

» An entity's exposure to or insulation from an affiliate with high business risk

» Structural features or other limitations in financing agreements that restrict movements of funds, investments, provision of guarantees or collateral, etc.

» The relative size and financial significance of any particular OpCo to the HoldCo and the family

[16] See paragraph at the end of this section for approaches to Hybrid HoldCos.

See also those factors noted in Notching for Structural Subordination of Holding Companies.

Our approach to a Hybrid HoldCo (see definition in Appendix C) depends in part on the importance of its non-utility operations and the availability of information on individual businesses. If the businesses are material and their individual results are fully broken out in financial disclosures, we may be able to assess each material business individually by reference to the relevant Moody's methodologies to arrive at a composite assessment for the combined businesses. If non-utility operations are material but are not broken out in financial disclosures, we may look at the consolidated entity under more than one methodology. When non-utility operations are less material but could still impact the overall credit profile, the difference in business risks and our estimation of their impact on financial performance will be qualitatively incorporated in the rating.

Higher Barriers to Cash Movement with Financing Predominantly at the OpCos

Where higher barriers to cash movement exist on an OpCo or OpCos due the regulatory framework or debt structural features, ratings among family members are likely to be more differentiated. For instance, for utility families with OpCos in the US, where regulatory barriers to free cash movement are relatively high, greater importance is generally placed on the stand-alone credit profile of the OpCo.

Our observation of major defaults and bankruptcies in the US sector generally corroborates a view that regulation creates a degree of separateness of default probability. For instance, Portland General Electric (Baa1 RUR-up) did not default on its securities, even though its then-parent Enron Corp. entered bankruptcy proceedings. When Entergy New Orleans (Ba2 stable) entered into bankruptcy, the ratings of its affiliates and parent Entergy Corporation (Baa3 stable) were unaffected. PG&E Corporation (Baa1 stable) did not enter bankruptcy proceedings despite bankruptcies of two major subsidiaries - Pacific Gas & Electric Company (A3 stable) in 2001 and National Energy Group in 2003.

The degree of separateness may be greater or smaller and is assessed on a case by case basis, because situational considerations are important. One area we consider is financing arrangements. For instance, there will tend to be greater differentiation if each member of a family has its own bank credit facilities and difficulties experienced by one entity would not trigger events of default for other entities. While the existence of a money pool might appear to reduce separateness between the participants, there may be regulatory barriers within money pools that preserve separateness. For instance, non-utility entities may have access to the pool only as a borrower, only as a lender, and even the utility entities may have regulatory limits on their borrowings from the pool or their credit exposures to other pool members. If the only source of external liquidity for a money pool is borrowings by the HoldCo under its bank credit facilities, there would be less separateness, especially if the utilities were expected to depend on that liquidity source. However, the ability of an OpCo to finance itself by accessing capital markets must also be considered. Inter-company tax agreements can also have an impact on our view of how separate the risks of default are.

For a HoldCo, the greater the regulatory, economic, and geographic diversity of its OpCos, the greater its potential separation from the default probability of any individual subsidiary. Conversely, if a HoldCo's actions have made it clear that the HoldCo will provide support for an OpCo encountering some financial stress (for instance, due to delays and/or cost over-runs on a major construction project), we would be likely to perceive less separateness.

Even where high barriers to cash movement exist, onerous leverage at a parent company may not only give rise to greater notching for structural subordination at the parent, it may also pressure an OpCo's rating, especially when there is a clear dependence on an OpCo's cash flow to service parent debt.

While most of the regulatory barriers to cash movement are very real, they are not absolute. Furthermore, while it is not usually in the interest of an insolvent parent or its creditors to bring an operating utility into a bankruptcy proceeding, such an occurrence is not impossible.

The greatest separateness occurs where strong regulatory insulation is supplemented by effective ring-fencing provisions that fully separate the management and operations of the OpCo from the rest of the family and limit the parent's ability to cause the OpCo to commence bankruptcy proceedings as well as limiting dividends and cash transfers. Typically, most entities in US utility families (including HoldCos and OpCos) are rated within 3 notches of each other. However, it is possible for the HoldCo and OpCos in a family to have much wider notching due to the combination of regulatory imperatives and strong ring-fencing that includes a significant minority shareholder who must agree to important corporate decisions, including a voluntary bankruptcy filing.

Lower Barriers to Cash Movement with Financing Predominantly at the OpCos

Our approach to rating issuers within a family where there are lower regulatory barriers to movement of cash from OpCos to HoldCos (e.g., many parts of Asia and Europe) places greater emphasis on the credit profile of the consolidated group. Individual OpCos are considered based on their individual characteristics and their importance to the family, and their assigned ratings are typically banded closely around the consolidated credit profile of the group due to the expectation that cash will transit relatively freely among family entities.

Some utilities may have OpCos in jurisdictions where cash movement among certain family members is more restricted by the regulatory framework, while cash movement from and/or among OpCos in other jurisdictions is less restricted. In these situations, OpCos with more restrictions may vary more widely from the consolidated credit profile while those with fewer restrictions may be more tightly banded around the other entities in the corporate family group.

Appendix C: Brief Descriptions of the Types of Companies Rated Under This Methodology

The following describes the principal categories of companies rated under this methodology:

Vertically Integrated Utility: Vertically integrated utilities are regulated electric or combination utilities (see below) that own generation, distribution and (in most cases) electric transmission assets. Vertically integrated utilities are generally engaged in all aspects of the electricity business. They build power plants, procure fuel, generate power, build and maintain the electric grid that delivers power from a group of power plants to end-users (including high and low voltage lines, transformers and substations), and generally meet all of the electric needs of the customers in a specific geographic area (also called a service territory). The rates or tariffs for all of these monopolistic activities are set by the relevant regulatory authority.

Transmission & Distribution Utility: Transmission & Distribution utilities (T&Ds) typically operate in deregulated markets where generation is provided under a competitive framework. T&Ds own and operate the electric grid that transmits and/or distributes electricity within a specific state or region.

T&Ds provide electrical transportation and distribution services to carry electricity from power plants and transmission lines to retail, commercial, and industrial customers. T&Ds are typically responsible for billing customers for electric delivery and/or supply, and most have an obligation to provide a standard supply or provider-of-last-resort (POLR) service to customers that have not switched to a competitive supplier. These factors distinguish T&Ds from Networks, whose customers are retail electric suppliers and/or other electricity companies. In a smaller number of cases, T&Ds rated under this methodology may not have an obligation to provide POLR services, but are regulated in sub- sovereign jurisdictions. The rates or tariffs for these monopolistic T&D activities are set by the relevant regulatory authority.

Local Gas Distribution Company: Distribution is the final step in delivering natural gas to customers. While some large industrial, commercial, and electric generation customers receive natural gas directly from high capacity pipelines that carry gas from gas producing basins to areas where gas is consumed, most other users receive natural gas from their local gas utility, also called a local distribution company (LDC). LDCs are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area. Specifically, LDCs typically transport natural gas from delivery points located on large-diameter pipelines (that usually operate at fairly high pressure) to households and businesses through thousands of miles of small-diameter distribution pipe (that usually operate at fairly low pressure). LDCs are typically responsible for billing customers for gas delivery and/or supply, and most also have the responsibility to procure gas for at least some of their customers, although in some markets gas supply to all customers is on a competitive basis. These factors distinguish LDCs from gas networks, whose customers are retail gas suppliers and/or other natural gas companies. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Integrated Gas Utility: Integrated gas regulated utilities are regulated utilities that deliver gas to all end users in a particular service territory by sourcing the commodity; operating transport infrastructure that often combines high pressure pipelines with low pressure distribution systems and, in some cases, gas storage, re-gasification or other related facilities; and performing other supply-related activities, such as customer billing and metering. The rates or tariffs for the totality of these activities are set by the relevant regulatory authority. Many integrated gas utilities are national in scope.

Combination Utility: Combination utilities are those that combine an LDC or Integrated Gas Utility with either a vertically integrated utility or a T&D utility. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Regulated Generation Utility: Regulated generation utilities (Regulated Gencos) are utilities that almost exclusively have generation assets, but their activities are generally regulated like those of vertically integrated utilities. In the US, this means that the purchasers of their output (typically other investor-owned, municipal or cooperative utilities) pay a regulated rate based on the total allowed costs of the Regulated Genco, including a return on equity based on a capital structure designated by the regulator (primarily FERC). Companies that have been included in this group include certain generation companies (including in Korea and China) that are not rate regulated in the usual sense of recovering costs plus a regulated rate of return on either equity or asset value. Instead, we have looked at a combination of governmental action with respect to setting feed-in tariffs and directives on how much generation will be built (or not built) in combination with a generally high degree of government ownership, and we have concluded that these companies are currently best rated under this methodology. Future evolution in our view of the operating and/or regulatory environment of these companies could lead us to conclude that they may be more appropriately rated under a related methodology (for example, Unregulated Utilities and Power Companies).

Independent System Operator: An Independent System Operator (ISO) is an organization formed in certain regional electricity markets to act as the sole chief coordinator of an electric grid. In the areas where an ISO is established, it coordinates, controls and monitors the operation of the electrical power system to assure that electric supply and demand are balanced at all times, and, to the extent possible, that electric demand is met with the lowest-cost sources. ISOs seek to assure adequate transmission and generation resources, usually by identifying new transmission needs and planning for a generation reserve margin above expected peak demand. In regions where generation is competitive, they also seek to establish rules that foster a fair and open marketplace, and they may conduct price-setting auctions for energy and/or capacity. The generation resources that an ISO coordinates may belong to vertically integrated utilities or to independent power producers. ISOs may not be rate-regulated in the traditional sense, but fall under governmental oversight. All participants in the regional grid are required to pay a fee or tariff (often volumetric) to the ISO that is designed to recover its costs, including costs of investment in systems and equipment needed to fulfill their function. ISOs may be for profit or not-for-profit entities.

In the US, most ISOs were formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC), but the ISO that operates solely in Texas falls under state jurisdiction. Some US ISOs also perform certain additional functions such that they are designated as Regional Transmission Organizations (or RTOs).

Transmission-Only Utility: Transmission-only utilities are solely focused on owning and operating transmission assets. The transmission lines these utilities own are typically high-voltage and allow energy producers to transport electric power over long distances from where it is generated (or received) to the transmission or distribution system of a T&D or vertically integrated utility. Unlike most of the other utilities rated under this methodology, transmission-only utilities primarily provide services to other utilities and ISOs. Transmission-only utilities in most parts of the world other than the US have been rated under the Regulated Networks methodology.

Utility Holding Company (Utility HoldCo): As detailed in Appendix B, regulated electric and gas utilities are often part of corporate families under a parent holding company. The operating subsidiaries of Utility HoldCos are overwhelmingly regulated electric and gas utilities.

Hybrid Holding Company (Hybrid HoldCo): Some utility families contain a mix of regulated electric and gas utilities and other types of companies, but the regulated electric and gas utilities represent the majority of the consolidated cash flows, assets and debt. The parent company is thus a Hybrid HoldCo.

Appendix D: Key Industry Issues Over the Intermediate Term

Political and Regulatory Issues

As highly regulated monopolistic entities, regulated utilities continually face political and regulatory risk, and managing these risks through effective outreach to key customers as well as key political and regulatory decision-makers is, or at least should be, a core competency of companies in this sector. However, larger waves of change in the political, regulatory or economic environment have the potential to cause substantial changes in the level of risk experienced by utilities and their investors in somewhat unpredictable ways.

One of the more universal risks faced by utilities currently is the compression of allowed returns. A long period of globally low interest rates, held down by monetary stimulus policies, has generally benefitted utilities, since reductions in allowed returns have been slower than reductions in incurred capital costs. Essentially all regulated utilities face a ratcheting down of allowed and/or earned returns. More difficult to predict is how regulators will respond when monetary stimulus reverses, and how well utilities will fare when fixed income investors require higher interest rates and equity investors require higher total returns and growth prospects.

The following global snapshot highlights that regulatory frameworks evolve over time. On an overall basis in the US over the past several years, we have noted some incremental positive regulatory trends, including greater use of formula rates, trackers and riders, and (primarily for natural gas utilities) de-coupling of returns from volumetric sales. In Canada, the framework has historically been viewed as predictable and stable, which has helped offset somewhat lower levels of equity in the capital structure, but the compression of returns has been relatively steep in recent years. In Japan, the regulatory authorities are working through the challenges presented by the decision to shut down virtually all of the country's nuclear generation capacity, leading to uncertainty regarding the extent to which increased costs will be reflected in rate increases sufficient to permit returns on capital to return to prior levels. China's regulatory framework has continued to evolve, with fairly low transparency and some time-to-time shifts in favored versus less-favored generation sources balanced by an overall state policy of assuring sustainability of the sector, adequate supply of electricity and affordability to the general public. Singapore and Hong Kong have fairly well developed and supportive regulatory frameworks despite a trend towards lower returns, whereas Malaysia, Korea and Thailand have been moving towards a more transparent regulatory framework. The Philippines is in the process of deregulating its power market, while Indian power utilities continue to grapple with structural challenges. In Latin America, there is a wide dispersion among frameworks, ranging from the more stable, long established and predictable framework in Chile to the decidedly unpredictable framework in Argentina. Generally, as Latin American economies have evolved to more stable economic policies, regulatory frameworks for utilities have also shown greater stability and predictability.

All of the other issues discussed in this section have a regulatory/political component, either as the driver of change or in reaction to changes in economic environments and market factors.

Economic and Financial Market Conditions

As regulated monopolies, electric and gas utilities have generally been quite resistant to unsettled economic and financial market conditions for several reasons. Unlike many companies that face direct market-based competition, their rates do not decrease when demand decreases. The elasticity of demand for electricity and gas is much lower than for most products in the consumer economy.

When financial markets are volatile, utilities often have greater capital market access than industrial companies in competitive sectors, as was the case in the 2007-2009 recession. However, regulated electric and gas utilities are by no means immune to a protracted or severe recession.

Severe economic malaise can negatively affect utility credit profiles in several ways. Falling demand for electricity or natural gas may negatively impact margins and debt service protection measures, especially when rates are designed such that a substantial portion of fixed costs is in theory recovered through volumetric charges. The decrease in demand in the 2007-2009 recession was notable in comparison to prior recessions, especially in the residential sector. Poor economic conditions can make it more difficult for regulators to approve needed rate increases or provide timely cost recovery for utilities, resulting in higher cost deferrals and longer regulatory lag. Finally, recessions can coincide with a lack of confidence in the utility sector that impacts access to capital markets for a period of time. For instance, in the Great Depression and (to a lesser extent) in the 2001 recession, access for some issuers was curtailed due to the sector's generally higher leverage than other corporate sectors, combined with a concerns over a lack of transparency in financial reporting.

Fuel Price Volatility and the Global Impact of Shale Gas

The ability of most utilities to pass through their fuel costs to end users may insulate a utility from exposure to price volatility of these fuels, but it does not insulate consumers. Consumers and regulators complained vociferously about utility rates during the run-up in hydro-carbon prices in 2005-2008 (oil, natural gas and, to a lesser extent, coal). The steep decline in US natural gas prices since 2009, caused in large part by the development of shale gas and shale oil resources, has been a material benefit to US utilities, because many have been able to pass through substantial base rate increases during a period when all-in rates were declining. Shale hydro-carbons have also had a positive impact, albeit one that is less immediate and direct, on non-US utilities. In much of the eastern hemisphere, natural gas prices under long-term contracts have generally been tied to oil prices, but utilities and other industrial users have started to have some success in negotiating to de-link natural gas from oil. In addition, increasing US production of oil has had a noticeable impact on world oil prices, generally benefitting oil and gas users.

Not all utilities will benefit equally. Utilities that have locked in natural gas under high-priced long- term contracts that they cannot re-negotiate are negatively impacted if they cannot pass through their full contracted cost of gas, or if the high costs cause customer dissatisfaction and regulatory backlash. Utilities with large coal fleets or utilities constructing nuclear power plants may also face negative impacts on their regulatory environment, since their customers will benefit less from lower natural gas prices.

Distributed Generation Versus the Central Station Paradigm

The regulation and the financing of electric utilities are based on the premise that the current model under which electricity is generated and distributed to customers will continue essentially unchanged for many decades to come. This model, called the central station paradigm (because electricity is generated in large, centrally located plants and distributed to a large number of customers, who may in fact be hundreds of miles away), has been in place since the early part of the 20th century. The model has worked because the economies of scale inherent to very large power plants has more than offset the cost and inefficiency (through power losses) inherent to maintaining a grid for transmitting and distributing electricity to end users.

Despite rate structures that only allow recovery of invested capital over many decades (up to 60 years), utilities can attract capital because investors assume that rates will continue to be collected for at least that long a period. Regulators and politicians assume that taxes and regulatory charges levied on electricity usage will be paid by a broad swath of residences and businesses and will not materially discourage usage of electricity in a way that would decrease the amount of taxes collected. A corollary assumption is that the number of customers taking electricity from the system during that period will continue to be high enough such that rates will be reasonable and generally more attractive than other alternatives. In the event that consumers were to switch en masse to alternate sources of generating or receiving power (for instance distributed generation), rates for remaining customers would either not cover the utility's costs, or rates would need to be increased so much that more customers may be incentivized to leave the system. This scenario has been experienced in the regulated US copper wire telephone business, where rates have increased quite dramatically for users who have not switched to digital or wireless telephone service. While this scenario continues to be unlikely for the electricity sector, distributed generation, especially from solar panels, has made inroads in certain regions.

Distributed generation is any retail-scale generation, differentiated from self-generation, which generally describes a large industrial plant that builds its own reasonably large conventional power plant to meet its own needs. While some residential property owners that install distributed generation may choose to sever their connection to the local utility, most choose to remain connected, generating power into the grid when it is both feasible and economic to do so, and taking power from the grid at other times. Distributed generation is currently concentrated in roof-top photovoltaic solar panels, which have benefitted from varying levels of tax incentives in different jurisdictions.

Regulatory treatment has also varied, but some rate structures that seek to incentivize distributed renewable energy are decidedly credit negative for utilities, in particular net metering.

Under net metering, a customer receives a credit from the utility for all of its generation at the full (or nearly full) retail rate and pays only for power taken, also at the retail rate, resulting in a materially reduced monthly bill relative to a customer with no distributed generation. The distributed generation customer has no obligation to generate any particular amount of power, so the utility must stand ready to generate and deliver that customer's full power needs at all times. Since most utility costs, including the fixed costs of financing and maintaining generation and delivery systems, are currently collected through volumetric rates, a customer owning distributed generation effectively transfers a portion of the utility's costs of serving that customer to other customers with higher net usage, notably to customers that do not own distributed generation. The higher costs may incentivize more customers to install solar panels, thereby shifting the utility's fixed costs to an even smaller group of rate-payers. To date, solar generation and net metering have not had a material credit impact on any utilities, but ratings could be negatively impacted if the programs were to grow and if rate structures were not amended so that each customer's monthly bill more closely approximated the cost of serving that customer.

In our current view, the possibility that there will be a widespread movement of electric utility customers to sever themselves from the grid is remote. However, we acknowledge that new technologies, such as the development of commercially viable fuel cells and/or distributed electric storage, could disrupt materially the central station paradigm and the credit quality of the utility sector.

Nuclear Issues

Utilities with nuclear generation face unique safety, regulatory, and operational issues. The nuclear disaster at Fukushima Daiichi had a severely negative credit impact on its owner, Tokyo Electric Power Company, Incorporated, as well as all the nuclear utilities in the country. Japan previously generated about 30% of its power from 50 reactors, but all are currently either idled or shut down, and utilities in the country face materially higher costs of replacement power, a credit negative.

Fukushima Daiichi also had global consequences. Germany's response was to require that all nuclear power plants in the country be shut by 2022. Switzerland opted for a phase-out by 2031. (Most European nuclear plants are owned by companies rated under other the Unregulated Utilities and Power Companies methodology.) Even in countries where the regulatory response was more moderate, increased regulatory scrutiny has raised operating costs, a credit negative, especially in the US, where low natural gas prices have rendered certain primarily smaller nuclear plants uneconomic. Nonetheless, we view robust and independent nuclear safety regulation as a credit-positive for the industry.

Other general issues for nuclear operators include higher costs and lower reliability related to the increasing age of the fleet. In 2013, Duke Energy Florida, Inc. decided to shut permanently Crystal River Unit 3 after it determined that a de-lamination (or separation) in the concrete of the outer wall of the containment building was uneconomic to repair. San Onofre Nuclear Generating Station was closed permanently in 2013 after its owners decided not to pursue a re-start in light of operating defects in two steam generators that had been replaced in 2010 and 2011.

Appendix E: Regional and Other Considerations

Notching Considerations for US First Mortgage Bonds

In most regions, our approach to notching between different debt classes of the same regulated utility issuer follows the guidance on notching corporate instrument ratings based on differences in security and priority of claim, including a one notch differential between senior secured and senior unsecured debt.[17] However, in most cases we have two notches between the first mortgage bonds and senior unsecured debt of regulated electric and gas utilities in the US.

Wider notching differentials between debt classes may also be appropriate in speculative grade. Additional insights for speculative grade issuers are provided in the publication "Loss Given Default for Speculative-Grade Companies."[18]

First mortgage bond holders in the US generally benefit from a first lien on most of the fixed assets used to provide utility service, including such assets as generating stations, transmission lines, distribution lines, switching stations and substations, and gas distribution facilities, as well as a lien on franchise agreements. In our view, the critical nature of these assets to the issuers and to the communities they serve has been a major factor that has led to very high recovery rates for this class of debt in situations of default, thereby justifying a two notch uplift. The combination of the breadth of assets pledged and the bankruptcy-tested recovery experience has been unique to the US.

In some cases, there is only a one notch differential between US first mortgage bonds and the senior unsecured rating. For instance, this is likely when the pledged property is not considered critical infrastructure for the region, or if the mortgage is materially weakened by carve-outs, lien releases or similar creditor-unfriendly terms.

Securitization

The use of securitization, a financing technique utilizing a discrete revenue stream (typically related to recovery of specifically defined expenses) that is dedicated to servicing specific securitization debt, has primarily been used in the US, where it has been quite pervasive in the past two decades. The first generation of securitization bonds were primarily related to recovery of the negative difference between the market value of utilities' generation assets and their book value when certain states switched to competitive electric supply markets and utilities sold their generation (so-called stranded costs). This technique was then used for significant storm costs (especially hurricanes) and was eventually broadened to include environmental related expenditures, deferred fuel costs, or even deferred miscellaneous expenses. States that have implemented securitization frameworks include Arkansas, California, Connecticut, Illinois, Louisiana, Maryland, Massachusetts, Mississippi, New Hampshire, New Jersey, Ohio, Pennsylvania, Texas and West Virginia. In its simplest form, a securitization isolates and dedicates a stream of cash flow into a separate special purpose entity (SPE). The SPE uses that stream of revenue and cash flow to provide annual debt service for the securitized debt instrument. Securitization is typically underpinned by specific legislation to segregate the securitization revenues from the utility's revenues to assure their continued collection, and the details of the enabling legislation may vary from state to state. The utility benefits from the securitization because it receives an immediate source of cash (although it gives up the opportunity to earn a return on the corresponding asset), and ratepayers benefit because the cost of the securitized debt is

17 A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.
18 A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report,

lower than the utility's cost of debt and much lower than its all-in cost of capital, which reduces the revenue requirement associated with the cost recovery.

In the presentation of US securitization debt in published financial ratios, we make our own assessment of the appropriate credit representation but in most cases follows the accounting in audited statements under US Generally Accepted Accounting Principles (GAAP), which in turn considers the terms of enabling legislation. As a result, accounting treatment may vary. In most states utilities have been required to consolidate securitization debt under GAAP, even though it is technically non- recourse.

In general, we view securitization debt of utilities as being on-credit debt, in part because the rates associated with it reduce the utility's headroom to increase rates for other purposes while keeping all-in rates affordable to customers. Thus, where accounting treatment is off balance sheet, we seek to adjust the company's ratios by including the securitization debt and related revenues for our analysis. Where the securitized debt is on balance sheet, our credit analysis also considers the significance of ratios that exclude securitization debt and related revenues. Since securitization debt amortizes mortgage-style, including it makes ratios look worse in early years (when most of the revenue collected goes to pay interest) and better in later years (when most of the revenue collected goes to pay principal).

Strong levels of government ownership in Asia Pacific (ex-Japan) provide rating uplift

Strong levels of government ownership have dominated the credit profiles of utilities in Asia Pacific (excluding Japan), generally leading to ratings that are a number of notches above the Baseline Credit Assessment. Regulated electric and gas utilities with significant government ownership are rated using this methodology in conjunction with the Joint Default Analysis approach in our methodology for Government-Related Issuers.[19]

Support system for large corporate entities in Japan can provide ratings uplift, with limits

Our ratings for large corporate entities in Japan reflect the unique nature of the country's support system, and they are higher than they would otherwise be if such support were disregarded. This is reflected in the tendency for ratings of Japanese utilities to be higher than their grid implied ratings. However, even for large prominent companies, our ratings consider that support will not be endless and is less likely to be provided when a company has questionable viability rather than being in need of temporary liquidity assistance.

[19] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Appendix F: Treatment of Power Purchase Agreements ("PPAs")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following: to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt, to fix the cost of power, or to comply with regulatory mandates regarding power sourcing, including renewable portfolio standards. While we regard PPAs that reduce operating or financial risk as a credit positive, some aspects of PPAs may negatively affect the credit of utilities. The most conservative treatment would be to treat a PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized.

Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner (which may be another utility or an Independent Power Producer – IPP); this charge typically covers a portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments usually help to cover the IPP's debt service and are made irrespective of whether the utility calls on the IPP to generate and deliver power. When the utility requires generation, a further energy charge, to cover the variable costs of the IPP, will also typically be paid by the utility. Some other similar arrangements are characterized as tolling agreements, or long-term supply contracts, but most have similar features to PPAs and are thus we analyze them as PPAs.

PPAs are recognized qualitatively to be a future use of cash whether or not they are treated as debt-like obligations in financial ratios

The starting point of our analysis is the issuer's audited financial statements – we consider whether the utility's accountants determine that the PPA should be treated as a debt equivalent, a capitalized lease, an operating lease, or in some other manner. PPAs have a wide variety of operational and financial terms, and it is our understanding that accountants are required to have a very granular view into the particular contractual arrangements in order to account for these PPAs in compliance with applicable accounting rules and standards. However, accounting treatment for PPAs may not be entirely consistent across US GAAP, IFRS or other accounting frameworks. In addition, we may consider that factors not incorporated into the accounting treatment may be relevant (which may include the scale of PPA payments, their regulatory treatment including cost recovery mechanisms, or other factors that create financial or operational risk for the utility that is greater, in our estimation, than the benefits received). When the accounting treatment of a PPA is a debt or lease equivalent (such that it is reported on the balance sheet, or disclosed as an operating lease and thus included in our adjusted debt calculation), we generally do not make adjustments to remove the PPA from the balance sheet.

However, in relevant circumstances we consider making adjustments that impute a debt equivalent to PPAs that are off-balance sheet for accounting purposes.

Regardless of whether we consider that a PPA warrants or does not warrant treatment as a debt obligation, we assess the totality of the impact of the PPA on the issuer's probability of default. Costs of a PPA that cannot be recovered in retail rates creates material risk, especially if they also cannot be recovered through market sales of power.

Additional considerations for PPAs

PPAs have a wide variety of financial and regulatory characteristics, and each particular circumstance may be treated differently by Moody's. Factors which determine where on the continuum we treat a particular PPA include the following:

» Risk management: An overarching principle is that PPAs have normally been used by utilities as a risk management tool and we recognize that this is the fundamental reason for their existence. Thus, we will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.

» Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly we regard these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive or if regulatory support for cost recovery deteriorates, the ability to pass through costs may decrease and, as circumstances change, our treatment of PPA obligations will alter accordingly.

» Price considerations: The price of power paid by a utility under a PPA can be substantially above or below the market price of electricity. A below-market price will motivate the utility to purchase power from the IPP in excess of its retail requirements, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or at an above-market price may suffer a financial burden if they do not get full recovery in retail rates. We will focus particularly on PPAs that have mark-to-market losses, which typically indicates that they have a material impact on the utility's cash flow.

» Excess Reserve Capacity: In some jurisdictions there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. We may determine that all of a utility's PPAs represent excess capacity, or that a portion of PPAs are needed for the utility's supply obligations plus a normal reserve margin, while the remaining portion represents excess capacity. In the latter case, we may impute debt to specific PPAs that are excess or take a proportional approach to all of the utility's PPAs.

» Risk-sharing: Utilities that own power plants bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. We will examine on a case-by case basis the relative credit risk associated with PPAs in comparison to plant ownership.

» Purchase requirements: Some PPAs are structured with either options or requirements to purchase the asset at the end of the PPA term. If the utility has an economically meaningful requirement to purchase, we would most likely consider it to be a debt obligation. In most such cases, the obligation would already receive on-balance sheet treatment under relevant accounting standards.

» Default provisions: In most cases, the remedies for default under a PPA do not include acceleration of amounts due, and in many cases PPAs would not be considered as debt in a bankruptcy scenario and could potentially be cancelled. Thus, PPAs may not materially increase Loss Given Default for the utility. In addition, PPAs are not typically considered debt for cross- default provisions under a utility's debt and liquidity arrangements. However, the existence of non-standard default provisions that are debt-like would have a large impact on our treatment of a PPA. In addition, payments due under PPAs are senior unsecured obligations, and any inability of the utility to make them materially increases default risk.

Each of these factors will be considered by our analysts and a decision will be made as to the importance of the PPA to the risk analysis of the utility.

Methods for estimating a liability amount for PPAs

According to the weighting and importance of the PPA to each utility and the level of disclosure, we may approximate a debt obligation equivalent for PPAs using one or more of the methods discussed below. In each case we look holistically at the PPA's credit impact on the utility, including the ability to pass through costs and curtail payments, the materiality of the PPA obligation to the overall business risk and cash flows of the utility, operational constraints that the PPA imposes, the maturity of the PPA obligation, the impact of purchased power on market-based power sales (if any) that the utility will engage in, and our view of future market conditions and volatility.

» Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, we may view the PPA as being most akin to an operating cost. Provided that the accounting treatment for the PPA is, in this circumstance, off-balance sheet, we will most likely make no adjustment to bring the obligation onto the utility's balance sheet.

» Annual Obligation x 6: In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of six (in most cases). This method is sometimes used in the capitalization of operating leases. This method may be used as an approximation where the analyst determines that the obligation is significant but cannot otherwise be quantified otherwise due to limited information.

» Net Present Value: Where the analyst has sufficient information, we may add the NPV of the stream of PPA payments to the debt obligations of the utility. The discount rate used will be our estimate of the cost of capital of the utility.

» Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility.

» Mark-to-Market: In situations in which we believe that the PPA prices exceed the market price and thus will create an ongoing liability for the utility, we may use a net mark-to-market method, in which the NPV of the utility's future out-of-the-money net payments will be added to its total debt obligations.

» Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. If the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

If we have determined to impute debt to a PPA for which the accounting treatment is not on-balance sheet, we will in some circumstances use more than one method to estimate the debt equivalent obligations imposed by the PPA, and compare results. If circumstances (including regulatory treatment or market conditions) change over time, the approach that is used may also vary.

Moody's Related Research

The credit ratings assigned in this sector are primarily determined by this credit rating methodology. Certain broad methodological considerations (described in one or more credit rating methodologies) may also be relevant to the determination of credit ratings of issuers and instruments in this sector. Potentially related sector and cross-sector credit rating methodologies can be found here.

For data summarizing the historical robustness and predictive power of credit ratings assigned using this credit rating methodology, see link.

Please refer to Moody's Rating Symbols & Definitions, which is available here, for further information. Definitions of Moody's most common ratio terms can be found in "Moody's Basic Definitions for Credit Statistics, User's Guide", accessible via this link.

» contacts continued from page 1

Analyst Contacts:

BUENOS AIRES +54.11.5129.260

Daniela Cuan +54.11.5129.261
Vice President - Senior Analyst
daniela.cuan@moodys.com

TORONTO +1.416.214.163

Gavin MacFarlane +1.416.214.386
Vice President - Senior Credit Officer
gavin.macfarlane@moodys.com

LONDON +44.20.7772.545

Douglas Segars +44.20.7772.158
Managing Director - Infrastructure Finance
douglas.segars@moodys.com

Helen Francis +44.20.7772.542
Vice President - Senior Credit Officer
helen.francis@moodys.com

HONG KONG +852.3551.307

Vivian Tsang +852.375.815.3
Associate Managing Director
vivian.tsang@moodys.com

SINGAPORE +65.6398.830

Ray Tay +65.6398.830
Vice President - Senior Credit Officer
ray.tay@moodys.com

TOKYO +81.3.5408.410

Mihoko Manabe +81.354.084.033
Associate Managing Director
mihoko.manabe@moodys.com

Mariko Semetko +81.354.084.20
Vice President - Senior Credit Officer
mariko.semetko@moodys.com

Report Number: 1072530

Author
Michael G. Haggarty

Production Associate
Masaki Shiomi

MOODY'S
INVESTORS SERVICE

FORWARD TEST YEARS FOR US ELECTRIC UTILITIES

Prepared for

Edison Electric Institute

Prepared by

Mark Newton Lowry, PhD
President

David Hovde, MS
Vice President

Lullit Getachew, PhD
Senior Economist

Matt Makos
Consultant

PACIFIC ECONOMICS GROUP RESEARCH LLC
22 East Mifflin St., Suite 302
Madison, Wisconsin USA 53703
608.257.1522

August 2010

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EXECUTIVE SUMMARY

U.S. investor-owned electric utilities (electric "IOUs") in jurisdictions with historical test year rate cases are grappling today with financial stresses that threaten their ability to serve the public well. Unit costs are rising because growth in sales volumes and other billing determinants is not keeping pace with growth in cost. Cost growth is stimulated by the need to rebuild and expand legacy infrastructure and to meet environmental and other public policy goals. In this situation historical test years, still used in almost 20 U.S. jurisdictions, can erode credit quality and condemn IOUs to chronic underearning.

This report provides an in depth discussion of the test year issue. It includes the results of empirical research which explores why the unit costs of electric IOUs are rising and shows that utilities operating under forward test years realize higher returns on capital and have credit ratings that are materially better than those of utilities operating under historical test years. The research suggests that shifting to a future test year is a prime strategy for rebuilding utility credit ratings as insurance against an uncertain future.

CHAPTER 1 (FORWARD TEST YEARS) provides an introduction to test year issues. Problems with historical test years are discussed. We explain that the "matching principle" used to rationalize historical test years assumes that cost and revenue remain balanced. This assumption doesn't hold when unit cost is rising. In a rising unit cost environment, rates based on historical test years are uncompensatory even in the year they are implemented. As a result, operating risk increases, raising the cost of obtaining funds in capital markets. Service quality may be compromised. Customers receive out of date price signals that encourage excessive consumption. The problems are aggravated when rate hearings are protracted. Utilities commonly respond with more frequent rate case filings but these raise regulatory cost, weaken performance incentives, and distract managers from their basic business while still not giving utilities sufficient attrition relief. It is unfair to expect utilities to offset revenue shortfalls produced by regulatory lag with higher productivity and unrealistic to think that they can do so. Forward test years can yield better results for utilities and their customers.

The unit cost trends of utilities are driven by conditions that are substantially beyond their control. These conditions include trends in input prices, productivity, and the average use of utility services by customers. For the matching principle to work, some combination of growth in utility productivity and average use must offset input price inflation.

Utility efforts to promote customer energy conservation slow growth in average use, thereby raising unit cost and making historical test year rates less compensatory. Forward test years can anticipate the slower growth in average use that results from utility conservation programs. They therefore help to remove utility disincentives to promote conservation aggressively.

The forecasts of costs and billing determinants that are made in a forward test year proceeding are uncertain but involve conditions that are at most two years into the future. A large part of utility cost is no more difficult to budget under forward test years than under historical test years. More volatile components of cost are often subject to true-up mechanisms. Conservative, well-reasoned methods for making forecasts are available. In a rising unit cost environment, the uncertainty of forecasts is less of a concern than the bias of historical test year rates.

Utilities seeking forward test years must be mindful of their high evidentiary burden. The following rate case measures bolster confidence.

- Provide concrete evidence as to why future test years and not historical test years are needed under current circumstances. Evidence concerning trends in the unit cost of utilities and in key unit cost drivers is especially pertinent.
- Provide cost and billing determinant data for one or more historical reference years and carefully explain methodologies for predicting cost and billing determinant changes between those years and the forward test year.
- Use forecasting methods that are transparent and based on reason but not needlessly complex.
- Routine variance reports comparing costs and billing determinants to utility forecasts can increase comfort that forecasts are unbiased.

CHAPTER 2 (TEST YEAR HISTORY) presents a brief history of test years in the United States. Historical test years became the norm in the U.S. because periods of stable or declining unit cost, made possible by slow price inflation and brisk growth in utility productivity and average use, were the rule rather than the exception in the electric utility industry prior to the late 1960s. Growth in productivity and average use have slowed enough in subsequent decades that unit cost has frequently risen. Under favorable business conditions, unit cost can still be flat for several years, making historical test years more reasonable. However, conditions like these can give way to conditions in which unit cost rises for years at a time.

Forward test years were adopted in many jurisdictions during the 1970s and 1980s as unit cost grew briskly, spurred by input price inflation and slower growth in average use and utility productivity. Unit cost growth was flat during most of the 1990s because business conditions driving unit cost growth were more favorable. Input price inflation slowed. Investment needs were more limited, as many utilities grew into capacity added during the construction cycle of the 1970's and early 1980's. Average use grew less rapidly than in the past but nonetheless increased appreciably in most years. Under these conditions, utilities were sometimes able to commit to multiyear base rate freezes.

Unit cost growth has since rebounded due to higher inflation, increased plant additions, and slowing growth in average use. Commissions in several states with historical test year traditions have recently moved in the direction of forward test years. Many of these states are in the West, where comparatively rapid economic growth has stimulated plant additions. The ranks of U.S. jurisdictions that use alternatives to historical test years have swollen and now encompass well over half of the total.

In summary, historical test years became the norm in U.S. rate cases during decades when unit cost was flat or declining due to remarkably brisk utility productivity and average use. Under contemporary conditions, in which average use grows slowly, if at all, and the productivity growth of utilities is more like that of the economy, unit cost may rise for extended periods undermining the matching principle.

CHAPTER 3 (EMPIRICAL SUPPORT FOR FORWARD TEST YEARS) presents results of some empirical research on test year issues. In original work for this paper, we calculated the unit cost trends of a sample of vertically integrated electric utilities from 1996 to 2008. Trends in business conditions that drive unit cost growth were measured. We also considered how test year policies affect credit metrics and utility operating performance.

Here are some salient results.

- The unit cost of sampled utilities was fairly stable from 1996 to 2002 but has since rebounded, averaging 2.3% annual growth from 2003 to 2008. The underlying causes of rising unit cost included higher input price inflation and capital spending and slower growth in the average system use of residential and commercial customers.
- In the three year period from 2006 to 2008 average use actually declined for the typical utility, pulled down by sluggish economic growth and government policies that encourage conservation. The decline was especially marked in states with large conservation programs.
- These results suggest that many IOUs may not be able in the future to count on brisk growth in average use by residential and commercial customers to buffer the impact on unit cost growth of input price inflation and increased plant additions. The problem will be considerably more acute in service territories where there are aggressive conservation programs.
- Utilities operating under forward test years were more profitable and had better credit ratings on average than those of utilities operating under historical test years. For example, from 2006 to 2008 utilities operating under forward test years realized an average return on capital of 9.2% and maintained a typical credit rating between A- and BBB+ whereas the utilities operating under historical test years realized an average return of 7.9% and maintained a typical credit rating between BBB and BBB-.
- Examination of recent trends in operation and maintenance ("O&M") expenses of utilities provides no evidence that historical test years encourage better cost management.

CHAPTER 4 (CONCLUDING REMARKS) provides some suggestions as to how interested regulators can get started down the road to forward test years.

1. Allow a forward test year on a trial basis for one interested utility.

2. Allow forward test years on an as needed basis when a utility makes a convincing case that rising unit costs make historical test years unjust and unreasonable.
3. Borrow one or two of the methods used in FTY rate cases to make additional adjustments to *historical* test year costs and billing determinants. For example, historical test year O&M expenses can be adjusted for forecasts of price inflation prepared by respected independent agencies. Special adjustments can be made for large plant additions that are expected to be finished in the near future.
4. Try a current test year (essentially the year of the rate case), which involves forecasts only one year into the future. Current test years can be combined with interim rate increases which are subject to true up when the rate case is finalized. A combination of a current test year and interim rates eliminates regulatory lag without the necessity of a two year forecast.

In states where regulators aren't ready to abandon historical test years but are sympathetic to the attrition problems caused by rising unit costs, alternative measures are available to relieve the financial attrition. Options include the following:

1. Make sure that historical test year calculations incorporate the full array of normalization, annualization, and known and measurable change adjustments that are used in other jurisdictions.
2. Grant utilities interim rate increases at the outset of a rate case. Even when later adjusted for the final rate case outcome, interim rates effectively reduce regulatory lag by a year.
3. Capital spending trackers can ensure timely recovery of the costs of plant additions, without rate cases, as assets become used and useful.
4. Several methods have been established to compensate utilities for acceleration in unit cost growth that results from flat or declining average system use. These include decoupling true up plans, lost revenue adjustment mechanisms, and higher customer charges.
5. Multiyear rate plans can give utilities rate escalation between rate cases for inflation and other business conditions that drive cost growth.

1. FORWARD TEST YEARS

This chapter provides an in depth discussion of test year issues. Basic test year concepts are introduced in Section 1.1. The rationale for forward test years is discussed in Section 1.2. The kinds of evidence used in forward test year proceedings are explored in Section 1.3.

1.1 Basic Concepts

1.1.1 Rate Cases

In the United States, rates for the services of energy utilities are periodically reset by regulators in litigated proceedings called rate cases. These cases typically take about nine or ten months to resolve and sometimes end in a settlement between contending parties which is approved by the regulator. The first year following approval of new rates is called the "rate year".

In a rate case, rates are reset to reflect the cost and service levels of the utility in a test year. The first step in this process is to establish a revenue "requirement" that is commensurate with a cost for service deemed reasonable for test year operating conditions. Rates are then established which recover the revenue requirement given the levels of service provided in the test year. The service levels (*e.g.* the number of customers served and the power delivery volume) are sometimes called "billing determinants".

Bills of energy utilities often contain charges to recover the cost of energy commodities (*e.g.* fuel and purchased power) procured on a customer's behalf which are separate from the charges to recover the cost of capital, labor, and other inputs used to operate their systems. The rates that recover the costs of non-energy inputs are commonly called "base" rates. Base rate revenues are sometimes called "margins".

Rates for the cost of energy procurement are commonly subject to true ups to recover the actual cost of energy procured. Base rates, on the other hand, have traditionally been reset only in rate cases. The earnings of utilities thus depend primarily on the difference between their base rate revenues and the cost of their base rate inputs.

1.1.2 Historical Test Years

Various kinds of test years are used in rate cases today. An historical test year ("HTY") is a twelve month period that ends before the rate case filing. It typically ends a few months before the filing because it is desirable for the test year to be as current as possible but it takes several months to properly account for a year of costs and take the other steps needed to prepare a rate case. The year between an historical test year and the rate year is sometimes called the "bridge year".

The passage of time between a test year and the rate year is sometimes called "regulatory lag".[1] The lag between an historical test year and the rate year is typically two years. A utility filing for new rates in calendar 2011, for example, would typically file in March or April of 2010 using a calendar 2009 test year. Thus, historical test year rates applicable in 2011 would typically reflect business conditions in 2009.

Regulatory lag in this case has several causes. One is the necessity of using a year of historical data in the rate case filing. Another is the time required to prepare a rate case filing. Still another is the time required to execute the rate case and reach a final decision on new rates.

Historical test year data are usually adjusted in some fashion to make rates more relevant to rate year business conditions. Costs and billing determinants are often normalized for the effects of volatile business conditions on the grounds that there is no reason to expect these conditions to be abnormal during the rate year. For example, if residential and commercial delivery volumes during an historical test year were elevated by unusually high summer temperatures, they may be statistically normalized to reflect average summer weather conditions. Other examples of abnormal events that can prompt normalization adjustments include ice storms, recessions, and extended generation plant outages.

Cost and output conditions in the historical test year may also be "annualized". Effects may be removed, for a full year, of conditions that occurred during part of the HTY but are not expected to continue. One example would be costs reported for the HTY that pertained to years before the test year. Another would be the volume and peak demand of a large industrial customer who has closed its local operations.

Impacts of conditions that occurred only during certain months of the test year and are expected to prevail in the near future may also be annualized. For example, the value of the rate base at the end of an historical test year is sometimes assumed to be applicable for

[1] This is one of several definitions of "regulatory lag" which are sometimes used in discussions of regulation. Another is the length of time between rate cases.

the entire year for purposes of calculating depreciation and the return on rate base. If union wage rates are raised in the last month of the HTY pursuant to the terms of a labor contract, labor expenses may be adjusted so that the higher cost per employee is effective for the entire year.

Cost and output data may, additionally, be adjusted for "known and measurable" (sometimes called "imminent certain") changes that have already occurred since the historical test year or are likely to occur in the near future. For example, if a labor contract provides for an escalation in union wages in the bridge year, HTY cost may be adjusted to reflect the wage rates provided in the contract.

The adjustments made to HTY cost and billing determinants vary across jurisdictions. While all such adjustments tend to make rates more relevant to rate year conditions, the HTY adjustment process often ignores important changes in business conditions that occur between an historical test year and a rate year. Here are some typical omissions.

- Cost is usually not adjusted to reflect future inflation in the prices of materials, services, and new equipment because the extent of such inflation isn't known with certainty.
- Costs of plant additions in the bridge year and the rate year are often omitted if their completion date and/or final cost aren't known with certainty.
- Billing determinants are usually not adjusted to reflect trends that are likely to occur after the test year because these are not known with certainty.
- Adjustments for known and measurable changes are sometimes limited arbitrarily to the bridge year.

1.1.3 Forward and Hybrid Test Years

A forward or future test year ("FTY") is a twelve month period that begins after the rate case is filed. Test year cost and billing determinants must in this case be forecasted, and forward test years are for this reason sometimes called forecasted test years. Utilities in some jurisdictions file rate cases with *multiple* forward test years. In the Canadian province of Alberta, for instance, it has recently been common for utilities to file for two forward test years in a rate case.

Most commonly, a forward test year begins about the time that the rate case is expected to end. The test year is then the same as the rate year. A utility filing on April 1

2010, for instance, might use calendar 2011 as its test year on the assumption that the rate case will take nine months to complete.

Some utilities use FTYs that begin about the time of the rate case filing. This kind of test year may be called a "current" FTY. The initial filing is in this case based entirely on forecasts but some months of actual data for the test year become available in the course of the proceeding.

Utilities in some states make rate case filings using test years that encompass some months *before* the filing and some months *afterwards*. Data for all months of the test year are then likely to become available during the course of the filing. This kind of test year has been called a "hybrid" or "partial" test year.

1.2 Rationale for Forward Test Years

1.2.1 The Financial Challenge

The Key Role of Unit Cost

We have noted that the rates that result from a rate case are designed to recover a revenue requirement that equals cost in a test year. In the case of an historical test year the new rates embody business conditions that are typically about two years older than those of the rate year. Business conditions are likely to change between an historical test year and the rate year, causing both cost and revenue to differ from the HTY level. For rates to be exactly compensatory, base rate cost and revenue must differ from their HTY levels in the same proportion.

The assumption that cost and revenue remain in balance underlies the matching principle that regulators still use to rationalize historical test years. Kamershen and Paul note in a thoughtful 1978 article on regulatory lag that "Philosophically, the strict [historical] test year assumes the past relationship among revenues, costs, and net investment will continue into the future."[2] A 2003 NARUC *Rate Case and Audit Manual* states in this regard that

> When looking at an historical test year, one of the first questions asked is whether the test year is too stale to make it a reasonable basis upon which to establish rates for a future period… In looking at the months beyond the end of the test year, have the growth rates for rate base, expenses, and revenues all remained fairly close and constant, maintaining the test year relationship

[2] David R. Kamershen and Chris W. Paul II, "Erosion and Attrition: A Public Utility's Dilemma", *Public Utilities Fortnightly*, December 1978, p. 23.

> among these three elements, or has one element changed dramatically, making the test year out of kilter with current operations? If so, can this situation be resolved through adjustments to the test year?[3]

Cost in the rate year is likely to be substantially higher than cost in an historical test year. To understand why, consider that cost growth in any business can be decomposed into inflation in the prices it pays for inputs plus the growth in its output less the growth in its productivity:

growth Cost = growth Input Prices + growth Output – growth Productivity. [1]

The productivity growth of a business is typically not rapid enough to offset the combined effects of input price inflation and output growth. A recent study reported in testimony by Pacific Economics Group ("PEG") found, for example, that a national sample of U.S. power distributors averaged 1.03% annual growth in multifactor productivity ("MFP") from 1996 to 2006 whereas input price growth averaged 2.72% and customer growth averaged 1.00%.[4] The productivity trend of sampled distributors was similar to that of the U.S. private business sector but far from sufficient to offset the combined effects on cost of input price inflation and customer growth.

As for base rate revenue during the rate year, it can exceed the HTY revenue requirement only due to growth in billing determinants because rates are fixed at levels that reflect HTY conditions. Whether or not historical test year rates are compensatory thus depends critically on whether *unit* cost is stable in the sense that growth in billing determinants has kept pace with cost growth. If cost growth exceeds growth in billing determinants, unit cost will rise and HTY rates will be uncompensatory.

An element of complexity is added when it is considered that a utility offers many services and gathers revenue for each service from multiple charges, each with its own billing determinant. A bill for residential service, for instance, typically involves a flat monthly charge called a "customer" or "basic" charge and a "volumetric" (per kWh) charge. In this world of multiple billing determinants, historical test years will yield uncompensatory rates to the extent that cost growth between the test year and the rate year exceeds a *weighted average* of the growth in billing determinants, where the weight for each determinant is its

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[3] NARUC Staff Subcommittee on Accounting and Finance, *Rate Case and Audit Manual*, Summer 2003.
[4] Mark Newton Lowry, *et al., Revenue Adjustment Mechanisms for Central Vermont Public Service Corporation*, Exhibit CVPS-Rebuttal-MNL-2 in Docket No. 7336, June 2008.

share of the total base rate revenue. In other words, rates are uncompensatory when cost growth exceeds the growth in a billing determinant *index*. This is the definition of growth in a *unit cost index*.

The utility uses most of its base rate revenue to pay its workforce, vendors of materials and services (including construction services), bondholders, and tax authorities. The residual margin, called net income or earnings, is available to provide the company's shareholders with a return on their investments. The return on equity is the component of cost that is most at risk for non-recovery when base rate revenue falls short of cost. When historical test year rates are non-compensatory they can reduce a utility's rate of return on equity ("ROE") materially.

Unit Cost Drivers

If the unit cost growth of a utility has made new historical test year rates non-compensatory, it may fairly be asked whether utility actions could have stopped the growth and avoided the problem. Research over many years has shown that the unit cost of a utility is driven chiefly by changes in business conditions that are beyond its control. Growth in the unit cost of a utility's base rate inputs depends on inflation in the prices it pays for those inputs, growth in the productivity with which it uses the inputs, and an average use effect:

growth Unit Cost = growth Input Prices – (growth Productivity + Average Use). [2]

We discuss each of these unit cost "drivers" in turn.

Input Price Inflation Inflation routinely occurs in the prices utilities pay for labor, materials, services, and equipment. Since utilities have capital-intensive technologies, inflation in the price of capital is an especially important driver of their input price growth. The trend in the price of capital depends chiefly on trends in construction costs, tax rates, and the going rates of return on debt and equity in capital markets.[5]

Productivity The productivity growth of a utility depends on various conditions that include technological change, the realization of scale economies, and the pace of plant additions as

[5] The impact of construction cost on price inflation is complex. In setting rates, utility plant is valued in historical dollars. The cost of service thus depends on prices paid for construction in past decades. Construction costs in more recent years matter more because the corresponding assets are less depreciated. The rate base will tend, on average, to reflect construction costs more than a decade into the past. For most utilities, new investments therefore embody more than a decade of construction cost inflation compared to investments of average vintage. This is one of the reasons why unusually large plant additions can increase the rate base so substantially.

well as utility efforts to root out inefficiencies. Plant additions may boost efficiency gains in the long run but can slow them in the short run, especially if they involve major investments such as new base load generating units, advanced metering infrastructure, or an accelerated program to replace aging infrastructure. Scale economies depend on the pace of output growth and on whether the utility is so large that it has reached a minimum efficient scale at which incremental scale economies from output growth aren't available.

The ability of utilities to achieve productivity surges is limited in the short run. Since technology is capital intensive, the depreciation and return on rate base associated with older investments --- which cannot be changed in the short run --- account for a large share of the total cost of base rate inputs. A utility can increase productivity only by slowing growth in O&M expenses and plant additions. Opportunities to achieve *sustained* productivity gains often involve sizable upfront costs and net gains may not occur for more than a year. A downsizing of the labor force, for instance, may involve severance payments. The chief means for a utility to trim its cost in the very short run is to defer maintenance expenses and plant additions. Such deferrals must be followed by higher expenses in short order if service quality is to be maintained. A utility can't rely on a deferral strategy year after year when it is filing frequent rate cases.

Average Use A utility's unit cost growth also depends on the difference in the impact that its output growth has on its revenue and its cost. When output growth boosts revenue more than cost, unit cost growth slows. When output growth causes cost to rise more rapidly than revenue, unit cost growth accelerates.

A utility's output growth has different impacts on revenue and cost when two conditions are present. One is that the design of base rates doesn't reflect the drivers of base rate input cost. The other is that billing determinants tend to grow at a different rate than cost drivers.

Consider, first, whether the design of utility base rates is cost causative. The cost of a utility's base rate inputs is largely fixed in the short run with respect to system use. Cost is much more sensitive to growth in the number of customers served.[6] As for billing determinants, we have seen that utility tariffs for most services involve multiple charges. These include one or more "variable" charges that are so called because they vary with

[6] Cost growth may also depend, in the long run, on the growth in peak demand and/or the delivery volume.

system use. Volumetric charges vary with the volume of power delivered. "Demand" charges vary with the peak level of demand (*i.e.* the highest hourly volume registered during the month). There are, additionally, "fixed" charges that are so called because they do not vary with a customer's use of the system during the billing period. Chief amongst the fixed charges of electric utilities are customer charges. Residential and small business customers account for the bulk of a utility's base rate revenue because these customers account for the bulk of a utility's cost. In these customer classes, base rate revenue is drawn chiefly from volumetric charges.

Under these circumstances, the difference between the way that output growth affects revenue and cost is chiefly a matter of the difference between the trends in the volume of sales to residential and small business customers and the trends in the number of customers served. This is equivalent to the trends in the delivery *volume per customer* of these service classes, which are sometimes referred to as the trends in their average (system) use. Unit cost growth slows when average use rises and accelerates when growth in average use slows.

In the electric utility industry, as in most sectors of the economy, the productivity growth of utilities has for decades been a good bit slower than the inflation in the prices they pay for inputs.[7] The recent PEG study noted earlier, for example, found that power distributor productivity growth fell short of input price growth by about 169 basis points annually on average from 1996 to 2006.[8] Under conditions like these, the average use trends of residential and small-volume business customers play an important role in determining whether a utility's unit cost rises. If growth in average use is *brisk* (*e.g.* 1.5 to 2% annually), the difference between input price and cost efficiency growth can be offset.[9] If average use is *static*, unit cost will rise substantially even under normal inflationary conditions. If average use is *declining*, the rise in unit cost can be quite rapid.

Recent changes in state and federal policy are encouraging more electricity demand-side management ("DSM") and development of customer-sited solar resources. These policies include net metering, tighter appliance efficiency standards and building codes, and

[7] The difference is greater in periods of brisk input price inflation and smaller in periods of slow inflation, since productivity does not characteristically rise and fall with inflation.
[8] Lowry *et al.* (2008) *op. cit.*
[9] Irston Barnes wrote, for example, in a classic treatise on rate regulation, that "as an offset to such factors making for rising rates, the increased volume of business that usually accompanies an upward movement of prices may so reduce the overhead charges per unit as to make any increase in rates unnecessary". See Irston R. Barnes, *The Economics of Public Utility Regulation* (New York: F.S. Crofts, 1942).

subsidies for energy efficiency investments. Our discussion suggests that such programs can accelerate unit cost growth by slowing growth in average use. Whether or not the utility provides DSM programs, average use can become static or decline, removing a key means by which utilities have traditionally coped with input price inflation and avoided unit cost growth. The problem can be remedied by redesigning rates in ways that raise customer charges. But rate designs are regulated and regulators in the United States generally do not sanction high customer charges.[10]

Implications Our analysis suggests that the unit cost of an electric utility is likely to rise, making historical test year rates non-compensatory, to the extent that the following external business conditions prevail.

- Input price inflation is brisk.
- Utilities need to make large plant additions that temporarily slow productivity growth.
- Average use of the utility system is static or declining.

Situations in which unit cost is stable, encouraging use of historical test years, include those in which inflation is slow, utilities aren't making large plant additions, and average use is growing briskly.

A program to accelerate the replacement of aging distribution facilities provides a classic example of the non-compensatory nature of historical test year rates. Suppose that a power distributor replaces 10% of its distribution infrastructure during a year when new rates are implemented. The new plant has capacity similar to the plant replaced but reflects more than forty years of construction cost inflation. The company's rate base will rise substantially, temporarily slowing productivity growth and accelerating unit cost growth. Even with normal growth in input prices and average use a utility with rates based on historical test years may earn little return on this sizable investment for as much as two years after it becomes used and useful.

Conclusions

These results permit us to draw several conclusions concerning the reasonableness of historical test years in ratemaking.

[10] High customer charges are more common for U.S. gas utilities and for gas and electric IOUs in Canada.

1) Historical test years are rationalized by a matching principle that assumes a balance of cost and revenue. Our analysis shows that this relationship is not balanced in a rising unit cost environment.
2) An individual utility reporting that rates produced by historical test years are uncompensatory may be suspected by stakeholders of poor cost management. However, research shows that a utility's unit cost trend is determined primarily by business conditions over which it has little control. These include the trends in input price inflation, average use, and the need for plant additions.
3) In a rising unit cost environment, the ability of a utility to "take a hair cut" between the historical test year and the rate year is limited. Long term performance gains involve upfront costs. Deferment of expenses lowers cost today at the expense of higher costs in the future.
4) Absent favorable operating conditions, the rise in a utility's unit cost due to changing business conditions may be so great that it is unable to earn its allowed rate of return under historical test year rates even with normal productivity gains. As Kamerschen and Paul comment, "while a utility is never guaranteed that it will earn its authorized fair rate of return, if no allowance is made for attrition or the other explosive elements, the utility is denied a realistic opportunity of earning the permitted rate of return."[11] In this situation, rates produced by historical test years are inherently unjust and unreasonable. This can prompt the investment community to downgrade its credit valuations, not just for the subject utility but for other utilities in the same jurisdiction.
5) Firms in competitive markets have ways of coping with rising unit costs that aren't available to utilities. The prices a competitive firm receives for its products will tend to rise at the same pace as the unit cost of its industry. Firms experiencing unit cost growth in excess of growth in sales prices can always scale back their offerings. A utility, in contrast, charges prices set by regulators which may not be reflective of unit cost trends. The utility is obligated to provide service even if prices are non-compensatory due to flawed ratemaking practices.

[11] Kamerschen and Paul *op. cit.* p. 23.

6) Unit cost pressures are not constant over time. Several years of flat unit cost can give way to a sustained period of rising unit cost. Thus, historical test years can produce reasonable results for many years and then become uncompensatory for many years due to rising unit cost. A utility's success at earning its allowed ROE during a string of recent years does not necessarily mean that a forward test year isn't warranted prospectively.
7) Forward test years have major advantages over historical test years in a rising unit cost environment. Rates are more likely to reflect unit cost conditions in the rate year and are, to this extent, more just and reasonable. Customers receive better price signals. Lower operating risk reduces the utility's cost of securing funds in capital markets. This benefit is especially important in periods of large plant additions, when high borrowing costs can have an especially large impact on the embedded cost of debt.
8) Whether or not unit cost is rising, historical test years do not adjust rates for slowdowns in volume growth, between the test year and the rate year, which are due to utility conservation initiatives. They therefore dampen utility incentives to encourage conservation.

1.2.2 Uncertainty

Opponents of forward test years often stress the uncertainty of cost and billing determinant forecasts. Future costs cannot be verified. The changes in business conditions that drive unit cost growth (*e.g.* inflation and the in service dates on looming plant additions) can be hard to predict accurately. The impact that changing business conditions have on unit cost is not always well understood. Opponents also argue that utilities are incented to exaggerate future cost growth and to understate future growth in billing determinants. Cost and billing determinants in a historical test year are, meanwhile, known with certainty.

On the other hand, the projections at issue in a forward test year concern business conditions that are at most two years into the future. A large chunk of future cost, the depreciation and the return on older plant, is known with considerable certainty at the time that the forecast is made. There are many aids in the preparation of credible forecasts, as we discuss further in Section 1.3. Consider also that volatile components of a utility's unit cost (*e.g.* expenses for pensions and uncollectible bills) are often subject to trackers that reduce or eliminate the risk of bad forecasts.

Current test years involve less forecasting uncertainty because the test year is only a year into the future at the time that the rate case is filed. Actual data for some or all months of the test year become available in the course of the proceeding. The accuracy of the methods used to forecast cost and billing determinants can thus be tested against their ability to predict the actuals in some months of the test year.

FTY projections are, in any event, quickly followed by actual data, and a utility that makes forecasts that are consistently biased in its favor will find that its forecasts are discounted in ratemaking. Biased forecasts can even jeopardize a regulator's willingness to use forward test years. The other stakeholders to the rate case process have incentives to bias cost and sales forecasts in the other direction. These circumstances reduce or eliminate the bias of the forecasts on which FTY rates are ultimately based. If the forecast of future cost and output is accurate, the utility will receive revenue that is exactly equal to its cost. FTY rates will be fair to the utility and ratepayer alike, whereas historical test year rates are likely to be biased in a rising (or falling) unit cost environment.

On balance then forward test year rates, while involving some uncertainty, are likely to be more reflective of future business conditions than are historical test year rates in a rising unit cost environment. The uncertainty involved in basing rates on FTYs is no greater than that involved in rate freezes and other kinds of multiyear rate plans that are often approved by regulators. The Michigan Public Service Commission ("PSC") commented, in a recent decision on an FTY rate filing for Consumers Energy, that

> The basis for using a forward test year is to address the problem of regulatory lag between past and future costs. While the advantage of historical data is its objective and verifiable nature, it lacks the necessary forward perspective required in a changing economic environment. An historical test year is by definition not timely and may fail to adequately consider future demands….What is gained by dealing with data that is "known and measurable" can be lost in forcing a utility to operate with outdated numbers.[12]

[12] Michigan PSC *Opinion and Order*, Case U-175645, November 2009.

1.2.3 Regulatory Cost

A third consideration in weighing the advantages of historical and forward test years is regulatory cost. The net impact of forward test years on regulatory cost is difficult to assess. Forward test year rate cases typically do involve higher cost than rate cases based on historical test years because of the need for forecasts.

On the other hand, a number of the major issues in a rate case, including the depreciation rates and the rate of return on common equity, are not markedly more complicated in a forward test year proceeding. Depreciation on existing plant is easy to predict once a depreciation rate is established. Some of the more uncertain components of cost and revenue may be subject to trackers that mitigate rate case controversy. The cost of FTY rate cases falls as jurisdictions gain experience with forecasted evidence. Consider also that in a rising unit cost environment rates based on forward test years can, by reducing earnings attrition, sometimes reduce the frequency of rate cases.

1.2.4 Operating Efficiency

The effect of alternative test year approaches on utility operating efficiency is also frequently discussed in debates on test year approaches. Opponents of forward test years sometimes argue that they weaken utility incentives to operate efficiently. In a rising unit cost environment, an expectation that rates are going to be non-compensatory might encourage utilities to tighten their belts. FTY opponents also argue that a utility wishing to inflate its cost in an historical test year, in an effort to create higher rates in the rate year, would incur a real cost to do so.

On the other hand, the notion that rate cases generally weaken utility performance incentives is a central result of regulatory economics and is not confined to future test years. When a utility is operating under a series of annual rate cases with historical test years, cost savings this year lead quickly to lower rates. The fact that a forward test year involves forecasts does not in and of itself weaken performance incentives. Forward test year forecasts are often linked to actual costs in one or more historical reference years, so the utility must once again incur a real cost if it wishes to bolster its argument for higher costs in the test year.

Consider also that when unit cost is rising, the non-compensatory rates yielded by forward test years may cause utilities to file rate cases more frequently. This weakens performance incentives, and senior managers devote less time to the utility's basic business of providing quality service at a reasonable cost. Analysis by PEG Research has revealed that reducing the frequency of rate cases from one to three years increases a utility's productivity performance by about 50 basis points annually in the long run.[13] We therefore do not expect utility operating incentives to differ significantly between historical and forward test years on balance.

It is, in any event, unreasonable for stakeholders and regulators to acquiesce in non-compensatory HTY rates on the grounds that they encourage utilities to trim "fat" if the existence of fat has not been demonstrated in the rate case. J. Michael Harrison, an administrative law judge with the New York PSC, commented in this regard in a 1979 article on forward test years that

> It is reasonable to set rates conservatively when company's management or operations are significantly and demonstrably poor… Evidence of general management inadequacy, however, is rarely seen in rate cases and … management normally will be striving to improve efficiency in periods of continuously rising costs. Regulatory commissions certainly have an obligation to monitor operations and management effectiveness, but it does not appear justifiable to indulge in a presumption, absent specific evidence to the contrary, that deficient earnings can be attributed to management shortcomings rather than to unfavorable operating conditions.[14]

1.2.5 Other Considerations

Here are some additional considerations that merit note in a discussion of forward test year pros and cons.

- Forward test years encourage the utility, other stakeholders, and the Commission to focus more attention on the utility's plans for the future. Undesirable trends, such as rising costs that reflect inadequate attention to productivity growth, can be recognized and discouraged in advance of their occurrence. Budgeting is apt to play a more central role in cost management.

[13] See, for example, "Incentive Plan Design for Ontario's Gas Utilities", a presentation made by the senior author in work for the Ontario Energy Board in November 2006.
[14] J. Michael Harrison, "Forecasting Revenue Requirements", *Public Utilities Fortnightly*, March 1979, p. 13.

- Forward test year rate cases sharpen the ability of the regulatory community to undertake and review statistical analyses of unit cost trends. These same skills are useful in the design of multiyear rate plans in which rates are adjusted automatically between rate cases to reflect changing business conditions. Multiyear rate plans can reduce regulatory cost and strengthen utility performance incentives, creating benefits that can be shared with customers.

1.3 Evidentiary Basis for FTY Forecasts

Good evidence on future costs and billing determinants is critical to the effectiveness of forward test year rate cases. The New York PSC stated, in an order rejecting a forward test year for New York State Electric and Gas in 1972, that

> To justify the commission in deviating from its long-standing policy of using an actual test year adjusted for known changes, there must be a full showing that such a change is a practical necessity. This showing must encompass the twin requirements of substantial accuracy and an impending, uncontrollable diminution in profitability.

We have already discussed at some length the kinds of conditions that can cause unit cost to rise between an historical test year and the rate year. We consider here kinds of evidence used in FTY rate cases that increase the confidence of regulators that forecasts are accurate.

Linkage to Historical Data

Utilities in forward test year rate cases usually file detailed and extensive evidence concerning cost and billing determinants in one or more historical reference years.[15] Data for these years are usually subject to normalization and annualization adjustments like those used in historical test year filings. The utility will then present evidence on expected changes in cost and billing determinants between the historical reference year and the test year.[16] Cost projections are often made for the same detailed Uniform System of Account categories that are used in historical test year rate cases. J. Michael Harrison commented in this regard in his 1979 article that "the New York commission's requirement that a verifiable nexus be established between a forecast and an historical base of actual experience is a sine qua non

[15] An historical reference year is sometimes called a "base period".
[16] This sometimes includes a forecast of cost during the rate case year (if different), which is sometimes called the "bridge year".

for forecasting revenue requirements. The burden of proving the reasonableness of its filing remains with the utility company."[17]

Indexation

Indexation is used by several utilities in FTY rate cases to escalate cost items for changing business conditions. Recall from Section 1.2.1 that the growth in the cost of a utility equals the inflation in the prices it pays for inputs plus the growth in its output less the trend in its productivity. The trend in the productivity of utilities tends to be similar to the growth in their output. Testimony just prepared by PEG Research for San Diego Gas & Electric reports that, for a national sample of power distributors, MFP averaged 0.88% annual growth from 1999 to 2008 while the number of customers served averaged 1.37% average annual growth.[18] An assumption that productivity growth equals output growth makes it possible to escalate cost from historical reference year(s) values by the forecasted growth in prices. This is the most common use of indexing in FTY forecasts.

The United States is fortunate to have available some of the best data in the world on utility input price trends. One company, Whitman, Requardt and Associates, has for decades published "Handy Whitman Indexes" of trends in the construction costs of both gas and electric utilities.[19] These are available for six geographic regions of the United States for detailed asset classes. Another company, Global Insight, has a *Power Planner* service that has forecasts, updated quarterly, of construction cost indexes. Global Insight also forecasts inflation in the prices of labor, materials, and services used by gas and electric utilities.[20] The materials and service ("M&S") price indexes are available for the detailed O&M expense categories that are itemized in the FERC's Uniform System of Accounts. Global Insight input price indexes have been used for many years to adjust revenue requirements in the multiyear rate plans of California gas and electric utilities.

Some utilities instead escalate O&M expenses in rate cases using familiar macroeconomic price indexes. The gross domestic product price index ("GDPPI") is often preferred for this purpose to the better known consumer price index because the GDPPI assigns less weight to price volatile commodities, such as food and energy, which do not

[17] J. Michael Harrison, *op. cit.*, p. 13.
[18] Mark Newton Lowry *et al.*, *Productivity Research for San Diego Gas & Electric,* August 2010.
[19] Whitman, Requardt & Associates LLP, "The Handy-Whitman Index of Public Utility Construction Costs".
[20] A discussion of an early use of detailed inflation forecasts in ratemaking is found in Michael J. Riley and H. Kendall Hobbs, Jr. "The Connecticut Solution to Attrition", *Public Utilities Fortnightly*, November 1982.

loom large in base rate input costs. Our research over the years has found that the GDPPI and CPI both tend to understate escalation in the prices of utility O&M inputs. One reason is that they are measures of inflation in the economy's prices of final goods and services and therefore reflect the productivity growth of the U.S. economy, which has been substantial in recent years. In a recent report for Hawaiian Electric, for instance, PEG found that from 1996 to 2007 the GDPPI averaged 2.21% average annual growth whereas an index of the O&M input prices paid by HECO averaged 3.05% average growth.[21] The GDPPI should therefore inspire confidence as an O&M escalator that often yields reasonable results for customers.

Simple Trend Analyses

Simple approaches to forecasting based on historical trends can, if well designed, strike a reasonable balance between the desire of regulators for accuracy and simplicity. For example, a given cost item can equal its adjusted value in the historical reference year, plus a one or two-year escalation for the average annual growth of this cost for a group of peer utilities in recent years. This approach is more sensible to the extent that the recent inflation, productivity, and output trends of the peers are similar to those that the subject utility will experience in the near future. A refinement on this general approach would be to assume a trend in cost *per customer* equal to the recent historical trend of peer utilities and then to reach cost by adding a forecast of the utility's own customer growth. Simple methods like these have counterparts for the forecasting of billing determinants. For example, the volume of residential sales in a future test year can be forecasted as the expected number of customers multiplied by the expected volume per customer, where the latter is allowed to differ from the normalized value(s) in the historical reference year(s) by its normalized trend in the last three years.

Budgeting

Some utilities use the same figures in forward test year filings that they use in their own budgeting process.

[21] Mark Newton Lowry *et al.*, *Revenue Decoupling for Hawaiian Electric Companies*, Pacific Economics Group, January 2009. pp. 65-66.

Econometric Modeling

Econometric modeling is used by several utilities in FTY cost and billing determinant projections. In an econometric model, the variable to be forecasted is posited to be a function of one or more external business conditions. Model parameters are estimated using historical data on the variable to be forecasted and the business conditions. A rich theoretical and empirical literature is available to guide model development. Given forecasts of the business conditions, the model can forecast how cost will grow between one or more historical reference years and the forward test year.

Benchmarking

Utilities can bolster the confidence of regulators in their FTY cost forecasts by benchmarking them using data from other utilities. A variety of benchmarking methods are available, ranging from econometric modeling to peer group comparisons that use simple unit cost metrics. Public Service of Colorado, for instance, recently filed a study in an FTY rate case filing that benchmarked their non-fuel O&M expense forecast.[22] The study used an econometric benchmarking model as well as unit cost metrics for a Western Interconnect peer group. The authors found that the forecasted expenses reflected a high level of operating efficiency.

[22] See Public Service Company of Colorado's Exhibit MNL-1 in docket 09AL-299E before the Public Utilities Commission of Colorado, filed October 13, 2009.

2. TEST YEAR HISTORY AND PRECEDENTS

2.1 A BRIEF HISTORY

Few states have laws on the books that mandate a particular test year approach. Statutes instead commonly feature more general provisions on regulation such as guidelines that rates be just and reasonable, that terms of service be non-discriminatory, and that service be of good quality. Flexibility with respect to test years is also encouraged by the Supreme Court's influential *Hope* decision, which held that

> The Commission was not bound to the use of any single formula or combination of formulae in determining rates. Under the statutory [Natural Gas Act] standard of "just and reasonable" it is the result reached and not the method which is controlling…If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end.[23]

Historical test years were nonetheless the norm in the early history of electric utility rate cases, and this reflects the prevalence over many years of business conditions that were conducive to slow unit cost growth. Slow price inflation was a contributing factor. Table 1 shows the history of GDPPI inflation in the United States from 1930 to 2009. It can be seen that inflation was negative in most years of the 1930s but was brisk during World War II, the immediate post war years, and in 1951. After the Korean War, the table shows that GDPPI inflation averaged only 1.74% annually in the 1952-1965 period.

Table 1 also shows the trend in the MFP index for the electric, gas, and sanitary sector of the U.S. economy. This index was computed by the U.S. Bureau of Labor Statistics ("BLS") for many years and was sensitive to the productivity trend in the electric utility industry due to the industry's disproportionately large size. It can be seen that the productivity growth of the electric, gas, and sanitary sector was extraordinarily rapid during the 1952-65 period, averaging 4.13% per annum. This was more than double the MFP index trend for the U.S. non-farm private business sector as a whole.

Under these favorable operating conditions, the unit cost of the electric utilities was typically stable or declining.[24] Rate cases were rare and historical test years were the norm in the rate cases that did occur. Regulators gained confidence that the matching principle could

[23] 320 U.S. 591.

[24] See Paul Joskow, "Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation", *Journal of Law and Economics*, 1974 for an insightful discussion of some of this history.

Table 1

U.S. Inflation and Productivity Trends

		GDP Price Index		Multifactor Productivity: Private Non-Farm Business		Multifactor Productivity: Electric, Gas & Sanitary Sector	
	Year	Index	Growth	Index	Growth	Index	Growth
	1929	10.6		NA	NA	NA	NA
	1930	10.2	-3.94%	NA	NA	NA	NA
	1931	9.2	-10.45%	NA	NA	NA	NA
	1932	8.1	-12.08%	NA	NA	NA	NA
	1933	7.9	-2.66%	NA	NA	NA	NA
	1934	8.3	4.78%	NA	NA	NA	NA
	1935	8.5	1.97%	NA	NA	NA	NA
	1936	8.6	1.09%	NA	NA	NA	NA
	1937	8.9	3.61%	NA	NA	NA	NA
	1938	8.7	-1.90%	NA	NA	NA	NA
	1939	8.6	-1.27%	NA	NA	NA	NA
	1940	8.7	0.87%	NA	NA	NA	NA
	1941	9.2	6.32%	NA	NA	NA	NA
	1942	10.0	7.91%	NA	NA	NA	NA
	1943	10.6	5.47%	NA	NA	NA	NA
	1944	10.8	2.37%	NA	NA	NA	NA
	1945	11.1	2.52%	NA	NA	NA	NA
	1946	12.4	10.90%	NA	NA	NA	NA
	1947	13.7	10.54%	NA	NA	NA	NA
	1948	14.5	5.52%	53.0	NA	37.1	NA
	1949	14.5	-0.06%	53.8	1.41%	37.7	1.66%
	1950	14.6	0.78%	57.2	6.08%	40.5	7.20%
	1951	15.6	6.66%	58.6	2.47%	44.4	9.16%
	1952	16.0	2.15%	59.0	0.67%	46.3	4.19%
	1953	16.2	1.26%	59.9	1.59%	48.1	3.80%
	1954	16.3	1.01%	59.9	-0.12%	50.0	4.01%
	1955	16.6	1.42%	62.4	4.15%	53.9	7.41%
	1956	17.1	3.39%	61.6	-1.33%	56.6	4.99%
	1957	17.7	3.44%	62.3	1.11%	58.7	3.59%
	1958	18.1	2.28%	62.4	0.29%	60.3	2.71%
	1959	18.3	1.13%	65.2	4.35%	64.1	6.10%
	1960	18.6	1.39%	65.5	0.51%	66.0	2.95%
	1961	18.8	1.12%	66.6	1.54%	67.7	2.41%
	1962	19.1	1.36%	68.9	3.46%	70.9	4.68%
	1963	19.3	1.05%	70.8	2.68%	72.3	2.02%
	1964	19.6	1.54%	73.5	3.72%	76.1	5.02%
	1965	19.9	1.80%	75.6	2.82%	79.2	4.00%
	1966	20.5	2.80%	77.7	2.82%	82.4	4.07%
	1967	21.1	3.03%	77.8	0.06%	85.0	3.01%
	1968	22.0	4.16%	79.8	2.56%	88.8	4.42%
	1969	23.1	4.82%	79.2	-0.76%	91.2	2.69%
	1970	24.3	5.14%	78.8	-0.50%	92.7	1.56%
	1971	25.5	4.88%	81.3	3.11%	93.8	1.21%
	1972	26.6	4.22%	83.7	2.87%	95.4	1.70%
	1973	28.1	5.39%	86.1	2.87%	97.2	1.88%
	1974	30.7	8.66%	83.2	-3.35%	94.0	-3.31%
	1975	33.6	9.06%	83.6	0.43%	94.2	0.18%
	1976	35.5	5.58%	86.8	3.77%	95.4	1.28%
	1977	37.8	6.17%	88.1	1.46%	95.2	-0.25%
	1978	40.4	6.78%	89.4	1.47%	95.1	-0.04%
	1979	43.8	7.99%	88.8	-0.67%	94.0	-1.21%
	1980	47.8	8.75%	86.9	-2.20%	93.5	-0.53%
	1981	52.3	9.01%	86.5	-0.42%	93.5	0.04%
	1982	55.5	5.92%	83.5	-3.59%	92.6	-1.04%
	1983	57.7	3.87%	86.6	3.68%	91.4	-1.23%
	1984	59.8	3.69%	88.7	2.35%	94.5	3.34%
	1985	61.6	2.98%	89.2	0.65%	94.4	-0.16%
	1986	63.0	2.20%	90.6	1.47%	94.7	0.35%
	1987	64.8	2.76%	90.7	0.16%	94.8	0.04%
	1988	67.0	3.38%	91.7	1.04%	98.5	3.84%
	1989	69.5	3.71%	91.7	0.00%	98.9	0.44%
	1990	72.2	3.80%	92.0	0.40%	100.4	1.49%
	1991	74.8	3.47%	91.3	-0.80%	100.2	-0.18%
	1992	76.5	2.35%	93.5	2.39%	100.0	-0.21%
	1993	78.2	2.18%	93.7	0.18%	102.6	2.52%
	1994	79.9	2.08%	94.4	0.78%	103.2	0.67%
	1995	81.5	2.06%	94.5	0.09%	105.6	2.22%
	1996	83.1	1.88%	95.8	1.42%	106.9	1.24%
	1997	84.6	1.76%	96.5	0.66%	106.9	-0.02%
	1998	85.5	1.12%	97.7	1.28%	107.0	0.11%
	1999	86.8	1.46%	99.0	1.27%	NA	NA
	2000	88.6	2.15%	100.0	1.05%	NA	NA
	2001	90.7	2.24%	100.4	0.39%	NA	NA
	2002	92.1	1.60%	102.5	2.08%	NA	NA
	2003	94.1	2.13%	105.2	2.60%	NA	NA
	2004	96.8	2.80%	108.0	2.60%	NA	NA
	2005	100.0	3.28%	109.3	1.26%	NA	NA
	2006	103.3	3.21%	109.9	0.51%	NA	NA
	2007	106.2	2.82%	110.1	0.21%	NA	NA
	2008	108.5	2.11%	111.4	1.13%	NA	NA
	2009	109.7	1.16%	NA	NA	NA	NA
Averages	**1952-1965**		**1.74%**		**1.82%**		**4.13%**
	1973-1981		**7.49%**		**0.37%**		**-0.22%**
	1982-1991		**3.58%**		**0.54%**		**0.69%**
	1992-2003		**1.92%**		**1.18%**		**NA**
	2004-2008		**2.84%**		**1.14%**		**NA**

yield just and reasonable rates.

The unit cost growth of electric utilities accelerated in the late 1960s and remained high for about two decades thereafter for several reasons.

- Price inflation accelerated, spurred initially by the Vietnam War and subsequently by the oil price shocks of 1974-75 and 1979-80. During the 1973-81 period, GDPPI inflation averaged 7.49% annually. Inflation thereafter slowed but still averaged 3.58% annually during the 1982-91 period.
- Rising utility rates and slowing economic growth slowed growth in use per customer.
- Utility productivity growth, far from keeping pace with inflation, slowed substantially falling by 0.22% annually on average in the 1973-1981 period and averaging only 0.69% annual growth in the 1982-91 period. Factors contributing to the slowdown included the exhaustion of scale economies by some of the nation's larger electric utilities and the propensity of some utilities to continue making major plant additions despite slower demand growth.

Under these changed conditions, utilities in the two decades after 1967 sought financial relief by filing frequent rate cases. However, many utilities found that they could not earn their allowed ROE under newly established rates. One author commented in 1974, a particularly bad year, that "it would be difficult, if not impossible, to find a utility which has been able in the first year in which a rate increase was in effect to earn the return on which the rate increase was predicted".[25] A study found that the earned ROE on equity in the electric utility industry was more than 200 basis points below the allowed rate of return on average in 1974, 1979, and 1980.[26] Interest coverage fell markedly for many utilities, limiting their ability to issue new debt. Financing of new investments required greater reliance on issuance of new common stock, and the value of stock fell below the book value of assets in many cases. Articles about attrition and regulatory lag appeared with regularity in the trade press.[27]

[25] W. Truslow Hyde, "It Could Not Happen Here – But it Did", *Public Utilities Fortnightly*, June 1974.
[26] Walter G. French, "On the Attrition of Utility Earnings", *Public Utilities Fortnightly*, February 1981.
[27] See, as another example, Theodore F. Brophy, "The Utility Problem of Regulatory Lag", *Public Utilities Fortnightly*, January 1975.

Regulators responded to this situation with an array of measures, some of which had been used at one time or another in the past. The measures included interim rate increases; the inclusion of construction work in progress ("CWIP") in rate base; more widespread use of fuel adjustment clauses; the addition of an "attrition allowance" to the target ROE, and more widespread use of forward and hybrid test years. Adopters of FTYs in these years of brisk unit cost growth included the Federal Energy Regulatory Commission ("FERC") and state commissions in California, Connecticut, Florida, Georgia, Hawaii, and New York.

Some of these states initially experimented with hybrid test years which, as we have noted, make it possible to update rate filings as actual data for the later months of the test year become available. J. Michael Harrison explained in his 1979 article some grounds for dissatisfaction with hybrid test year experiments:

> Parties charged with testing or contesting a utility's rate case presentation were faced with figures and issues that changed and shifted through all phases of the case. Even after their direct evidentiary presentations were made, these parties were faced with a required reevaluation of their positions and the possibility that a host of new issues would be created by emerging actual data. The commission staff, which in New York bore the brunt of this burden, faced an almost impossible task of analyzing new data, even as its case went to the administrative law judge or commission for decision. It became clear that the value of the already completed hearings was being seriously undermined.[28]

The New York Commission decided in 1977 to move to fully forecasted test years consisting of the first twelve months expected under the new rates.[29]

The need for forward test years subsided with the slowdown of unit cost growth that occurred in the electric utility industry in the 1990s. This slowdown was driven primarily by a partial reversal of the business conditions that had previously caused brisk unit cost growth. During the 1992-2003 period GDPPI growth averaged only 1.92% per year. Yields on newly issued long term bonds fell substantially as the market lowered its expectation of future inflation. The productivity growth of the electric, gas, and sanitary sectors increased modestly, averaging 0.94% annually during the 1992-98 period, a trend similar to that of the private business sector. One reason for the productivity rebound was a slowdown in plant additions as the industry increased utilization of the generation and transmission capacity

[28] J. Michael Harrison, *op. cit.*, p. 12.
[29] New York Public Service Commission, "Statement of Policy on Test Periods in Major Rate Proceedings", November 1977.

built in the previous twenty years. Several electric utilities operated under base rate freezes during these years. Their willingness to agree to freezes reflected in part the generally favorable unit cost conditions but sometimes also reflected an expected spurt of productivity growth due to participation in mergers or acquisitions.

Interest in forward test years has renewed for electric utilities in recent years due to a renewed growth in unit cost, which is discussed in more detail in Section 3.1 below. We note here that general inflation accelerated after 2003, with GDPPI growth averaging 2.84% annually during the 2004-2008 period. Inflation slowed in 2009 but will likely rebound as the world economy recovers from the recession. Utility investment needs increased during the period to replace aging facilities, reverse declining generation capacity margins, implement "smart grid" technologies, and meet the rising demand for transmission services to reach remote sources of renewable energy and promote bulk power market competition. Growth in average use has slowed with slowing economic growth and new initiatives to promote energy conservation.

Interest in forward test years has been especially keen in the American west. Brisk economic growth in most western states has increased the need for plant additions. Here is a brief summary of changing test year policies in selected states.

Colorado

In Colorado, the commission rejected an FTY request by Public Service of Colorado in 1993 but acknowledged that "the purpose of a test year is to provide, as closely as possible, an interrelated picture of revenue, expense, and investment reasonably representative of the interrelationships that will be in place at the time the new rates proposed in a rate case will be in effect".[30] The commission did not forbid FTY evidence and encouraged the company to consider a *current* test year, an option that it said "might provide a promising mixture of comfort and flexibility acceptable to the parties and the commission.[31]

Public Service filed FTY evidence in a 2008 rate case but the approved settlement in the case was based on historical test year evidence.[32] In May 2009, Public Service again filed FTY evidence as it sought to include in its cost of service some major plant additions,

[30] PUC Colorado Decision No. C93-1346 in Docket No. 93S-001EG, October 1993, pp. 21-22.
[31] *Ibid*, p. 40.
[32] Docket No. 08S-520E.

including a new coal-fired generating unit and a smart grid build out, which would come online in late 2009 or 2010.[33] A settlement agreement, approved with modifications, based the revenue requirement on a historical 2008 test year with extraordinary adjustments to include the cost of the impending major plant additions. The company agreed not to file a rate case for two years.

This settlement also indicated an expectation that the company would file FTY evidence in its next rate case. It commits the company to provide companion historical test year evidence, including a detailed analysis of deviations between HTY and FTY results. The Company agreed to work with interested parties on reporting requirements with respect to such deviation analyses in order to facilitate the review of future cases.

Idaho

In Idaho the largest electric utility, Idaho Power, successfully used a hybrid test year in a rate case filing in 2003. In a 2009 filing it successfully used a test year beginning in January 2009.[34] This was essentially a current FTY.

Illinois

The move to forward test years is not confined to western states. Illinois utilities have long retained the right to file FTY rate cases and Integrys recently did so successfully for its North Shore Gas and Peoples Gas Light and Coke units.[35] Peoples has a major need to increase replacement investments in its aging system, which serves Chicago.

Michigan

In Michigan, utilities have used varied test year approaches. Recent legislation (2008 PA 286) explicitly sanctions forward test year filings. The law also permits utilities to "self-implement" interim rates if rate cases aren't resolved in 180 days. Consumers Energy and Detroit Edison have recently filed FTY rate cases successfully.

New Mexico

In New Mexico a bill was passed in 2009 that allows the state commission to use forward test years in electric and gas rate proceedings. The bill states that

[33] Docket No. 09AL-299E.
[34] Docket No. IPC-E-09-10.
[35] Dockets No. 09-0166 and 09-0167.

> In making a determination of just and reasonable rates of a utility, the commission shall select a test period that, on the basis of substantial evidence in the whole record, the commission determines best reflects the conditions to be experienced during the period when the rates determined by the commission take effect. If a utility proposes a future test period, a rebuttable presumption shall exist that a future test period best reflects the conditions to be experienced during the period when the rates determined by the commission take effect.[36]

The Bill was supported by majority voice vote of the New Mexico Public Regulation Commission. Public Service of New Mexico recently filed an FTY rate case.

Utah

Utah statutes were amended in 2003 to allow hybrid and forward test years for gas and electric utilities. The amended statutes state that

> If in the commission's determination of just and reasonable rates the commission uses a test period, the commission shall select a test period that, on the basis of the evidence, the commission finds best reflects the conditions that a public utility will encounter during the period when the rates determined by the commission will be in effect.[37]

The choice of a test year has since become an issue in the early stages of rate cases. In 2004, for example, PacifiCorp [d/b/a Rocky Mountain Power ("RMP")] filed a rate case based on a forward test year. It defended the FTY on the grounds that its costs were increasing due to rapid system growth and a plan to improve system reliability. An unopposed Test Year Stipulation acknowledged that the FTY was the most sensible test year for this case and provided for a task force to address test period procedural issues. The terms of the stipulation were not binding for future proceedings. The Commission commented in its order approving the stipulation that

> Each case needs to be considered on its own merits and the test period selected should be the most appropriate for that case. The test period selected for a utility in a particular case may not be appropriate for another utility or even the same utility in a different case. Some of the factors that need to be considered in selecting a test period include the general level of inflation, changes in the utility's investment, revenues, or expenses, changes in utility services, availability and accuracy of data to the parties, ability to synchronize the utility's investment, revenues, and expenses, whether the utility is in a cost

[36] New Mexico Senate Bill 477, 2009.
[37] Utah Code Annotated Section 54-4-4 (3).

> increasing or cost declining status, incentives to efficient management and operation, and the length of time the new rates are expected to be in effect.[38]

In December 2007, RMP filed a rate case based on a forward test year beginning in July 2008.[39] The Commission instead chose a current FTY beginning in January 2008. The Company was compelled to update its testimony to reflect the sanctioned test year. In its final decision in the case, the Commission instructed the Company to file a semi-annual "variance report" comparing its actual operating results to its rate case forecasts.

In April 2009, RMP filed a notice of intent to file a rate case in June 2009 based on a forward test year beginning in January 2010. A high level of capital investment was emphasized in advocating the need for an FTY. The Commission approved a Test Period Stipulation providing for a current FTY beginning in June 2009. The decision notes that the Division of Public Utilities argued in support of the stipulation that

> the stipulated test period, combined with the opportunity for the Company to request alternative cost recovery treatment for major plant additions, will balance the interest of the Company in reducing regulatory lag and the interests of customers by reducing the risks associated with the timing and cost of major capital additions projected to be completed 18 months into the future.[40]

Wyoming

In Wyoming, a stipulation approved in 2006 provided that RMP (d/b/a PacifiCorp) could, on a one time trial basis, file a rate case based on a forward test year. RMP filed a rate case in June 2007 using an FTY ending in August 2008. The Wyoming Public Service Commission approved a rate settlement based on the forecasts for this test year. They indicated a willingness to hear forward test year evidence in the general rate case but required the company to submit conventional historical test year evidence as well. The Commission also directed the company to prepare a report comparing its actual cost and billing determinants for the current test year to those which the company forecasted in the proceeding. In the event, the variance report stated that the company had overestimated its

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[38] Public Service Commission of Utah, "Order Approving Test Period Stipulation", Docket 04-035-42, October 2004.
[39] Public Service Commission of Utah, "Order on Test Period", Docket No. 07-035-93, February 2008.
[40] Public Service Commission of Utah, "Report and Order on Test Period Stipulation", Docket No. 09-035-23, June 2009.

cost by a small amount but overestimated its revenue and on balance did not earn its allowed rate of return for the year.

In July 2008, RMP filed a new rate case with a current FTY ending in June 2009 using calendar 2007 as a historical reference year. The company emphasized in its case the inability of historical test year rates to compensate the utility for sizable new investments in its system. The Commission approved a settlement that included a provision that RMP file historical test year evidence as well as any FTY evidence in its next rate proceeding.[41] RMP will continue to file operating results that will permit the Commission to review the accuracy of its FTY forecasts.

2.2 Current Status

Table 2 and Figure 1 detail the test year approaches that are currently in use across the United States. It can be seen that historical test years are now used by most large IOUs in less than twenty U.S. jurisdictions. Nearly as many jurisdictions (AL, CA, CT, FL, GA, HI, ME, MI, MN, MS, NY, OR, RI, TN, WI, and the FERC) use forward test years routinely, at least for larger utilities. Forward test years are also used in several Canadian jurisdictions. Four jurisdictions (AR, OH, NJ, & PA) use hybrid test years. An additional 13 jurisdictions are not neatly categorized. Here are some examples.

- Large utilities in Illinois, Kentucky, Maryland, and North Dakota utilities use various test years.
- As previously noted, test years used by utilities in Utah and Wyoming depend on conditions at the time of filing and New Mexico is heading in that direction.

2.3 Conclusions

In Section 1.2 we noted that the matching principle used in historical test year rate cases is based on the assumption that growth in billing determinants matches cost growth so that unit cost is stable. This is true when growth in utility productivity and average use somehow combine to offset the cost impact of input price growth. We report in this chapter that conditions like these have not been normal for electric utilities since the 1960s. Periods of unit cost stability can still occur, but are apt to be followed by periods of rising unit cost.

[41] Wyoming PSC Docket Number 20000-333-ER-08 (Record No. 11824), May 2009.

Table 2

Test Year Approaches of U.S. Jurisdictions

Forward (16)

State	Notes
Alabama	Alabama Power's Rate Stabilization and Equalization Factor is forward looking.
California	
Connecticut	Cost is based on a historical test year that is escalated to a future rate year.
FERC	Rate cases use forward test years while formula rate plans tend to use HTYs.
Florida	
Georgia	
Hawaii	
Maine	Cost is based on a historical test year that is escalated to a future rate year.
Michigan	
Minnesota	
Mississippi	
New York	
Oregon	
Rhode Island	Cost is based on a historical test year that is escalated to a future rate year.
Tennessee	
Wisconsin	

Hybrid (4)

State	Notes
Arkansas	
Ohio	
New Jersey	
Pennsylvania	

Transitional/Varying (13)

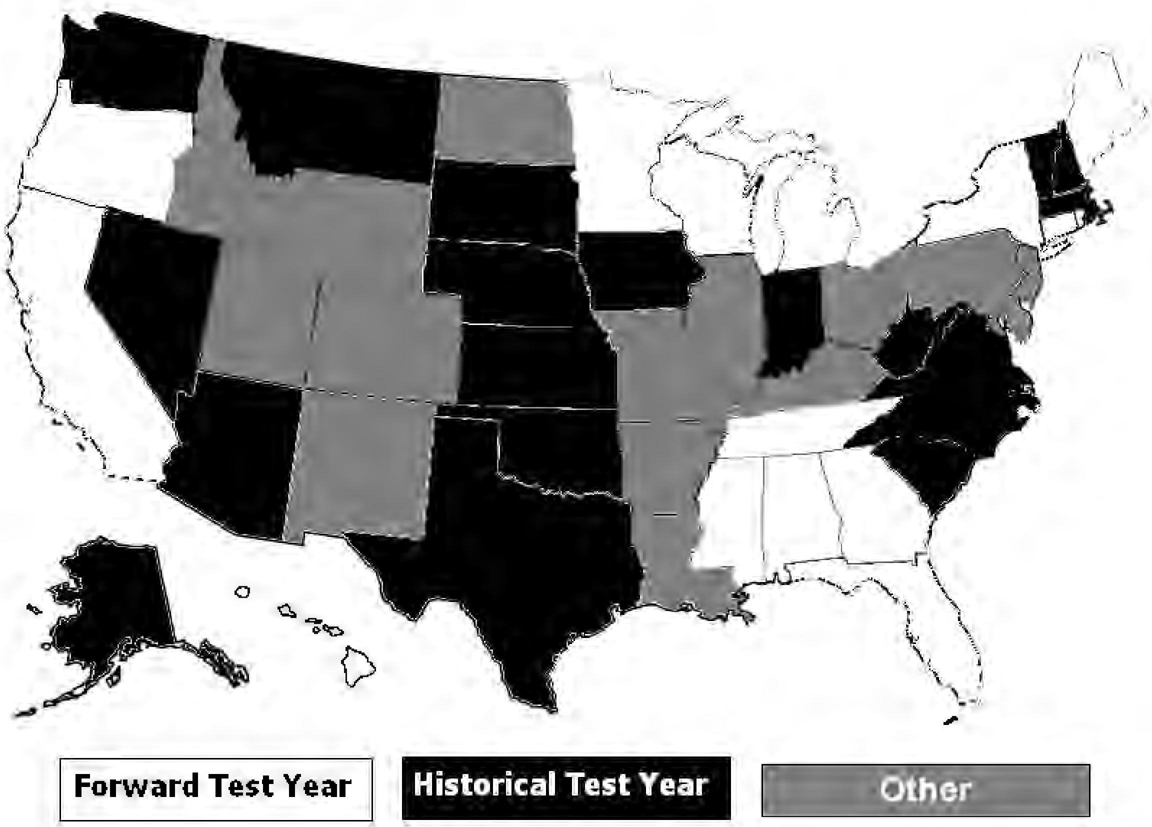
Utility Name	Notes
Colorado	Public Service of Colorado can file FTY evidence. No FTY rates have yet been approved but the most recent case made extraordinary HTY adjustments.
District of Columbia	PEPCO has filed rate cases using both hybrid and historical test years recently.
Delaware	Before restructuring FTY filings were common, but companies have used HTY in recent filings.
Idaho	
Illinois	Historic test years are the norm in IL. However, utilities have the right to make FTY filings and an FTY was accepted in a recent rate case of the Integrys gas utilities.
Kentucky	FTYs are legally authorized, but only Duke Energy has utilized them to date.
Louisiana	Cleco Power frequently uses hybrid test years. Entergy New Orleans recently had a hybrid test year approved via settlement.
Maryland	Baltimore Gas & Electric tends to file hybrid test years while other utilities tend to file historical test years.
Missouri	Utilities have the option to file hybrid year forecasts that are trued up during the course of the proceeding.
New Mexico	Recently passed law allows for use of FTY, but no rate case with an FTY has yet been approved.
North Dakota	Utilities use various test years including FTYs.
Utah	Test year selection is part of the rate case and can be contested. Several recent rate cases have used FTYs.
Wyoming	Rocky Mountain Power has recently had FTYs approved.

Historical (19)

Utility Name	Notes
Alaska	
Arizona	
Indiana	
Iowa	
Kansas	
Massachusetts	
Montana	
Nebraska	Nebraska has no electric IOUs in its jurisdiction. Gas companies are legally authorized to use FTYs, but no gas company has had FTY rates approved.
Nevada	
New Hampshire	
North Carolina	
Oklahoma	
South Carolina	
South Dakota	
Texas	
Vermont	
Virginia	
Washington	
West Virginia	

Figure 1

Map of Jurisdictions by Approved Test Year



Numerous regulators have moved away from historical test years in periods when unit cost is rising. Historical test year jurisdictions are now in the minority.

3. EMPIRICAL SUPPORT FOR FORWARD TEST YEARS

3.1 UNIT COST TRENDS OF U.S. ELECTRIC UTILITIES

In Section 1.2 we detailed the key role that the trend in the unit cost of utilities has in determining the reasonableness of historical test years and the need for forward test years. In original research for this paper, we have calculated the unit cost trends of a sample of vertically integrated electric utilities ("VIEUs"). In this section, we explain our research methods in some detail before discussing the results.

3.1.1 Data

The primary source of utility cost date used in the study was the FERC Form 1. Major investor-owned electric utilities in the United States are required by law to file this form annually. Data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Details of these accounts can be found in Title 18 of the Code of Federal Regulations.

Unit cost calculations also require data on billing determinants. Data on the number of customers served were drawn from FERC Form 1. Data on delivery volumes were drawn from Form EIA 861. The FERC Form 1 and Form EIA 861 data used in this study were gathered by SNL Financial, a respected commercial vendor.

Data were considered for inclusion in the sample from all major investor-owned VIEUs that did not offer gas distribution service or sell or spin off the bulk of their transmission assets in recent years. To be included in the study the data were required, additionally, to be plausible and not unduly burdensome to process. Data from the thirty four companies listed in Table 3 were used in the unit cost research. The sample period was 1996-2008. The year 2008 is the latest for which the requisite data were available when the study was prepared.

Supplemental data sources were used to measure input price trends. Handy Whitman indexes were used to measure electric utility construction cost trends. Global Insight indexes were used to measure trends in the prices of electric utility materials and services. Employment cost indexes prepared by the BLS were used to measure trends in labor prices. Regulatory Research Associates data was used to measure trends in target ROEs approved by regulators.

Table 3

Utilities Included in the Unit Cost Research

Company
Alabama Power
Appalachian Power
Arizona Public Service
Black Hills Power
Carolina Power & Light
Cleco Power
Columbus Southern Power
Dayton Power and Light
Duke Energy Carolinas
Empire District Electric
Entergy Arkansas
Florida Power & Light
Florida Power
Georgia Power
Gulf Power
Idaho Power
Indianapolis Power & Light
Kansas City Power & Light
Kentucky Power
Kentucky Utilities
Minnesota Power
Mississippi Power
Nevada Power
Ohio Power
Oklahoma Gas and Electric
Otter Tail Power
PacifiCorp
Portland General Electric
Public Service Company of Oklahoma
Southwestern Electric Power
Southwestern Public Service
Tampa Electric
Tucson Electric Power
Virginia Electric and Power

Number of utilities in sample: 34

3.1.2 Definition of Unit Cost

In Section 1.2.1 we discussed a measure of unit cost growth that is relevant in the appraisal of test years. It is constructed by taking the difference between growth in the net cost of base rate inputs and the growth in an index of utility billing determinants. For each sampled utility, we calculated the total cost of base rate inputs net of taxes as the sum of non-energy O&M expenses, depreciation, amortization, and return on rate base. Non-energy O&M expenses were calculated as total O&M expenses less customer service and information expenses and energy expenses that included those for steam power generation fuel, nuclear power generation fuel, other power generation fuel, and purchased power.[42] [43]

Return on rate base was calculated as the value of the rate base times a weighted average cost of capital ("WACC"). In constructing the WACC we assumed 50/50 weights for debt and common equity. The rate of return on debt was calculated as the ratio of the interest payments of electric utilities to the value of their debt as reported on the FERC Form 1. The ROE was calculated as the average applicable allowed ROEs of electric utilities as reported by Regulatory Research Associates.[44] The rate base for each utility was calculated as its net plant value less net accumulated deferred income taxes plus the value of its fuel, material, and supply inventories.

We reduced the base rate cost thus calculated by two kinds of "non-core" revenues, as is common in the calculation of retail base rate revenue requirements. One item deducted was Other Operating Revenue. This is the revenue from miscellaneous goods and services that include bulk power wheeling. The other component of non-core revenues was an estimate of the margin from power sales for resale.[45]

The growth in the billing determinant index used in our study is a weighted average of the growth in important billing determinants of electric utilities. The determinants used in index construction were the numbers of residential, commercial, and other retail customers

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[42]Customer service and information expenses were excluded because they tended to rise over the sample period due to expanding demand-side management programs. The cost of DSM programs is typically recovered using tracker-rider mechanisms.

[43] We also excluded the Other Expenses category of Other Power Supply Expenses. We believe that large and volatile commodity-related costs are sometimes reported in this category.

[44] In this calculation, we assumed that the target ROE approved for a utility in its most recent rate case was applicable until a new target ROE was approved.

[45] These margins were computed as the difference between sales for resale revenue and an estimate of the energy commodity costs used in power supply.

and the corresponding delivery volumes.[46] We weather normalized the volumes using econometric demand research. In constructing the index, the trends in the billing determinants thus assembled were weighted by our estimates of the typical shares of individual billing determinants in the base rate revenue requirements of VIEUs.[47] The estimates were drawn from a perusal of recent VIEU rate case filings.

3.1.3 Unit Cost Results

Unit Cost Trends

The average annual trends of the sampled utilities in their cost, billing determinants, and unit cost can be found in Table 4 and Figure 2. It can be seen that unit cost declined by a modest 0.78% annually on average in the 1996-2002 period as average growth in billing determinants exceeded average growth in cost. The average growth in unit cost was positive in only one year of this period. These results suggest that, under typical operating conditions, historical test years would have yielded compensatory outcomes in rate cases during this period.

In the 2003-2008 period, on the other hand, it can be seen that unit cost grew briskly, averaging about 2.31% annually. Utilities experienced unit cost growth on average in every year of the period. Cost averaged 1.98% annual growth from 1996 to 2002 and 4.36% annual growth thereafter. The normalized growth of billing determinants averaged 2.75% per annum through 2002 but only 2.05% per annum thereafter. Thus, growth in billing determinants slowed despite marked acceleration of cost growth.

Earnings Impact

To consider the earnings attrition resulting from 2.3% annual unit cost growth, consider that if the typical company in the sample earned its target ROE it would constitute about 13% of the total cost of its base rate inputs. Assuming two years of 2.3% unit cost growth, revenue based on prices reflecting only the normalized business conditions of the historical test year would be expected to result in a 4.45% base rate revenue shortfall. If there was no tax adjustment, this would reduce the return on equity by about 35%. Assuming

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[46] The retail peak demands of commercial and industrial customers are also important billing determinants but data on these were unavailable.

[47] We assigned the base rate revenue shares corresponding to demand charges to the "other retail" delivery volume, expecting that these volumes have trends that are similar to those of demand charge billing determinants.

Table 4

Trends in the Unit Cost of US Vertically Integrated Utilities

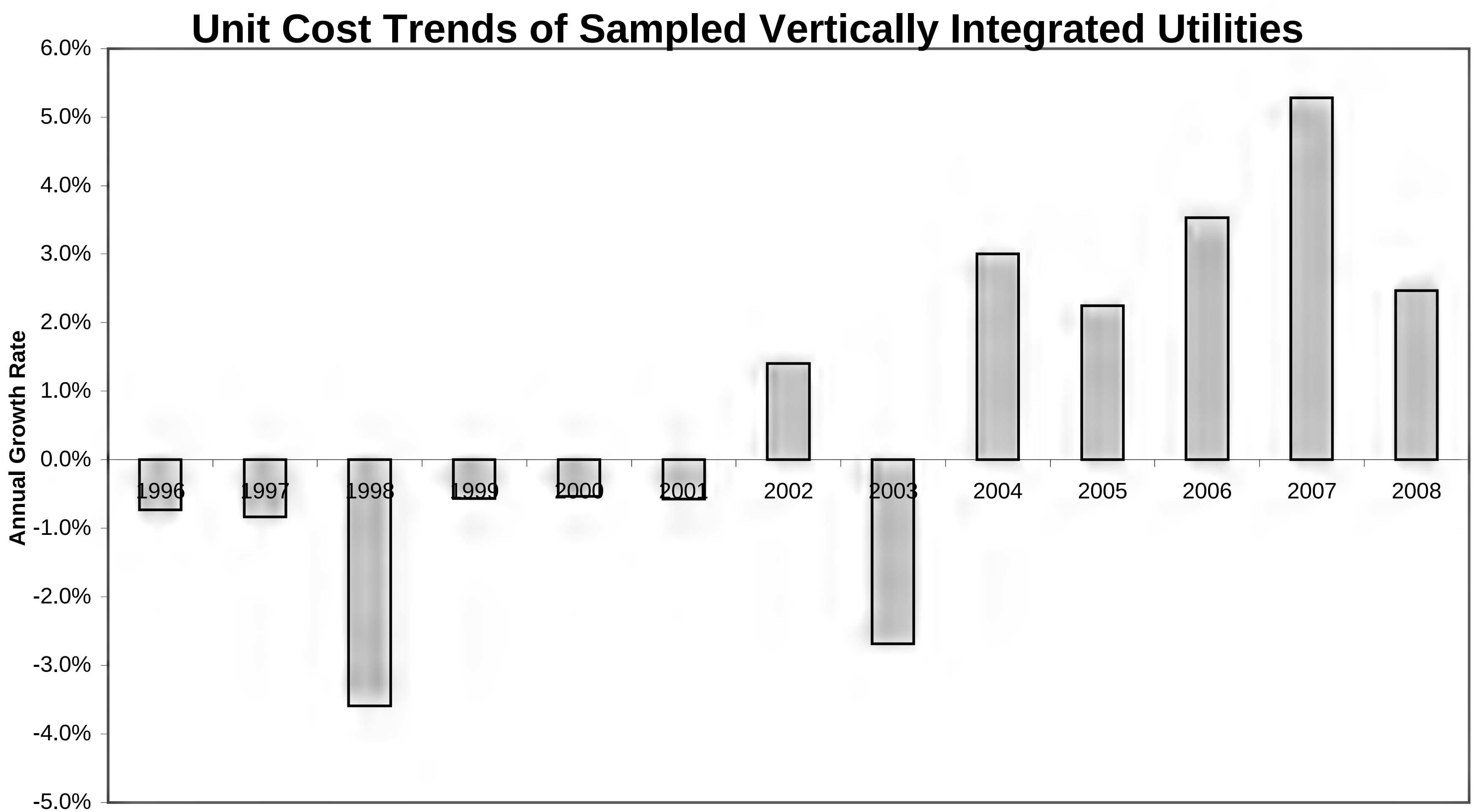
Sample Average Annual Growth Rates, Unweighted

Year	**Cost[1]**	**Billing Determinants[2]**	**Unit Cost**
1996	2.8%	3.5%	-0.7%
1997	1.4%	2.2%	-0.8%
1998	-0.7%	2.9%	-3.6%
1999	2.5%	3.0%	-0.6%
2000	3.4%	4.0%	-0.5%
2001	0.9%	1.4%	-0.6%
2002	3.6%	2.2%	1.4%
2003	1.6%	4.3%	-2.7%
2004	4.6%	1.6%	3.0%
2005	4.0%	1.8%	2.2%
2006	5.0%	1.5%	3.5%
2007	7.9%	2.6%	5.3%
2008	3.0%	0.5%	2.5%
Average Annual Growth Rates			
1996-2008	**3.08%**	**2.43%**	**0.65%**
1996-2002	**1.98%**	**2.75%**	**-0.78%**
2003-2008	**4.36%**	**2.05%**	**2.31%**

[1] The net cost formula is (Total O&M Expenses - Energy O&M Expenses - Customer Service and Information Expenses) + (Depreciation + Amortization + WACC x Rate Base) - (Other Operating Revenues + Estimated Resale Margin). The source of the cost data is FERC Form 1.

[2] The annual growth in billing determinants is a weighted average of the growth in residential, commercial, and other retail delivery volumes and customers served. The weights are shares in the base rate revenue requirement that are typical of vertically integrated electric utilities. Volumes were weather normalized by PEG Research using econometric demand modelling. The source of the raw volume data is Form EIA 861. The source of the customer data is FERC Form 1.

Figure 2


Unit Cost Trends of Sampled Vertically Integrated Utilities
Annual Growth Rate
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
-1.0%
-2.0%
-3.0%
-4.0%
-5.0%
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008

an allowed ROE of 11%, this would mean a drop in ROE of around 375 basis points before tax adjustments. While lower income taxes would mitigate the earnings impact, we may conclude from this analysis that historical test years would have been inherently non-compensatory for a utility operating under the *typical* business conditions facing VIEUs in recent years. Results would be much worse for utilities facing more pronounced unit cost pressures due, for example, to an accelerated program of replacement capex or a large scale DSM program.

Unit Cost Drivers

Input Prices Our discussion in Section 1.2.1 contained the result that input price inflation, productivity growth, and the trend in average use were key drivers of unit cost growth. We calculated for this report indexes of the inflation in the prices of base rate inputs faced by the sampled VIEUs. The growth rates of the summary input price indexes are weighted averages of the growth rates in indexes of prices for electric utility plant and O&M labor and materials and services. The index for each utility uses as weights the share of each input group in the total cost of the company's base rate inputs.[48] The index for the price of plant was calculated from the trends in bond yields, allowed returns on equity, and the Handy Whitman Construction Cost Index for vertically integrated electric utilities in the applicable region.

Results of our input price research are presented in Table 5 and Figure 3. It can be seen that the prices of base rate inputs averaged 2.76% annual inflation in the 1996-2002 period and 3.65% inflation in the 2003-2008 period --- an increase of 89 basis points. The price acceleration was primarily in materials and services and capital. M&S price inflation averaged 2.08% annually in the 1996-2002 period and 4.31% annually in the 2003-2008 period.

[48] An input price index with cost share weights effectively estimates the impact of price inflation on cost.

Table 5

Trends in Prices of Electric Utility Base Rate Inputs, 1996-2008

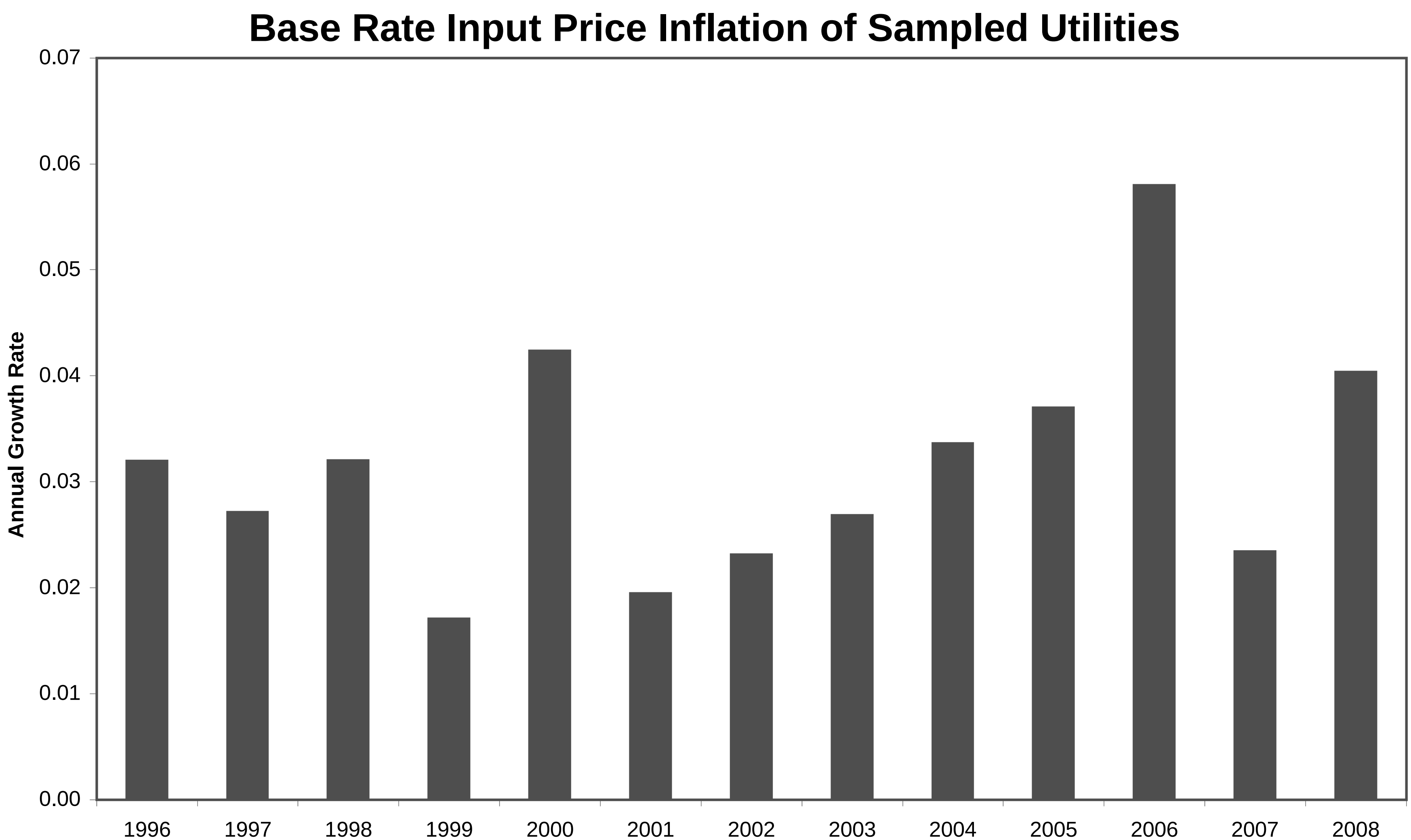
	Summary Input Price Index		**Labor**		**Materials & Services**		**Capital**	
Year	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate
1995	1.000		1.000		1.000		1.000	
1996	1.032	3.2%	1.033	3.2%	1.020	2.0%	1.034	3.3%
1997	1.061	2.7%	1.065	3.1%	1.042	2.1%	1.061	2.7%
1998	1.095	3.2%	1.108	4.0%	1.058	1.6%	1.098	3.4%
1999	1.114	1.7%	1.139	2.7%	1.076	1.6%	1.112	1.2%
2000	1.162	4.2%	1.193	4.6%	1.109	3.0%	1.158	4.1%
2001	1.185	1.9%	1.242	4.0%	1.135	2.4%	1.168	0.8%
2002	1.213	2.3%	1.301	4.6%	1.157	1.9%	1.186	1.5%
2003	1.246	2.7%	1.356	4.2%	1.189	2.7%	1.206	1.7%
2004	1.289	3.4%	1.428	5.1%	1.241	4.3%	1.227	1.7%
2005	1.337	3.7%	1.501	5.0%	1.303	4.9%	1.251	1.9%
2006	1.417	5.8%	1.652	9.6%	1.364	4.6%	1.303	4.1%
2007	1.451	2.3%	1.578	-4.6%	1.421	4.1%	1.352	3.6%
2008	1.510	4.0%	1.629	3.2%	1.498	5.3%	1.396	3.2%
Average Annual Growth Rate								
1996-2008		**3.17%**		**3.76%**		**3.11%**		**2.57%**
1996-2002		**2.76%**		**3.76%**		**2.08%**		**2.43%**
2003-2008		**3.65%**		**3.75%**		**4.31%**		**2.72%**

Sources

Labor	Calculated by PEG Research from BLS Employment Cost Indexes that include pensions and benefits
Materials & Services	Calculated by PEG Research using functional cost shares for sampled utilities obtained from FERC Form 1 and detailed electric utility M&S price indexes obtained from Global Insight's ***Power Planner.***
Capital	Calculated by PEG Reseach from Handy Whitman electric utility construction cost indexes Average yields on utility bonds calculated from FERC Form 1 data gathered by SNL Interactive Applicable allowed ROEs as reported by Regulatory Research Associates
Summary	Calculated by PEG Research from the labor, M&S, and capital price indexes using vertically integrated electric utility base rate input cost shares drawn from FERC Form 1

FERC Form 1 data gathered by SNL

Figure 3


Base Rate Input Price Inflation of Sampled Utilities
Annual Growth Rate
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0.00
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008

Plant Additions Large plant additions were noted in Section 1.2.1 to be an important driver of utility productivity growth. Table 6 and Figure 4 describe the trend in real (*i.e.* inflation adjusted) plant additions per customer of the sampled utilities. It can be seen that from 2003 through 2008, real plant additions were 25% higher on average than in the 1995-2002 period.

Average Use In Table 7 and Figure 5 we present information on the trends in weather normalized average use by the residential and commercial customers of a large sample of U.S. electric utilities from 1996 to 2008. The sample included specialized transmission and distribution utilizes as well as VIEUs. It can be seen that the growth rates in average use have tended to fall for both residential and commercial customers since 2002. The trend was more pronounced for residential customers. Growth in normalized average use of power by residential customers averaged 1.09% per year in the 1996-2002 period and 0.43% per year in the 2003-2008 period. Growth in weather-normalized average use by commercial customers averaged 1.04% per year in the 1996-2002 period and 0.74% per year in the 2003-2008 period.

The average use slowdown was especially pronounced in the 2006-2008 period. The normalized average use of residential customers averaged a slight 0.19% annual decline and average use by commercial customers was essentially flat. For this more recent period, we separately calculated trends for utilities in service territories with large DSM programs and the trends for utilities in other territories. The normalized average use by residential customers of utilities operating in territories with large DSM programs declined by a remarkable 0.68% on average.

These results suggest that the typical IOUs may not be able in the future to count on brisk growth in average use by residential and commercial customers to buffer the impact on unit cost growth of input price inflation and increased plant additions. The problem will be considerably more acute in service territories where there are aggressive conservation programs. Forward test years will be particularly uncompensatory where utilities must cope with the consequences for load of aggressive DSM programs.

Table 6

Real Plant Additions Per Customer of Sampled Utilities

	Real Additions to Plant in Service (1995=100)	Number of Customers (1995=100)	Real Additions per Customer (1995=100)
1995	100.00	100.00	100.00
1996	93.26	101.89	91.53
1997	85.99	103.99	82.70
1998	70.50	106.33	66.30
1999	89.82	108.20	83.01
2000	102.31	110.66	92.46
2001	111.46	112.80	98.81
2002	108.46	114.70	94.56
2003	148.32	116.57	127.23
2004	110.42	118.78	92.96
2005	115.52	120.98	95.49
2006	125.04	123.89	100.93
2007	149.51	125.82	118.83
2008	165.19	126.85	130.22
Averages			
1996-2002			87.05
2003-2008			110.94

Sources: Cost and cutomer data from FERC Form 1. Plant additions deflated using applicable regional Handy Whitman electric utility construction cost indexes.

Figure 4

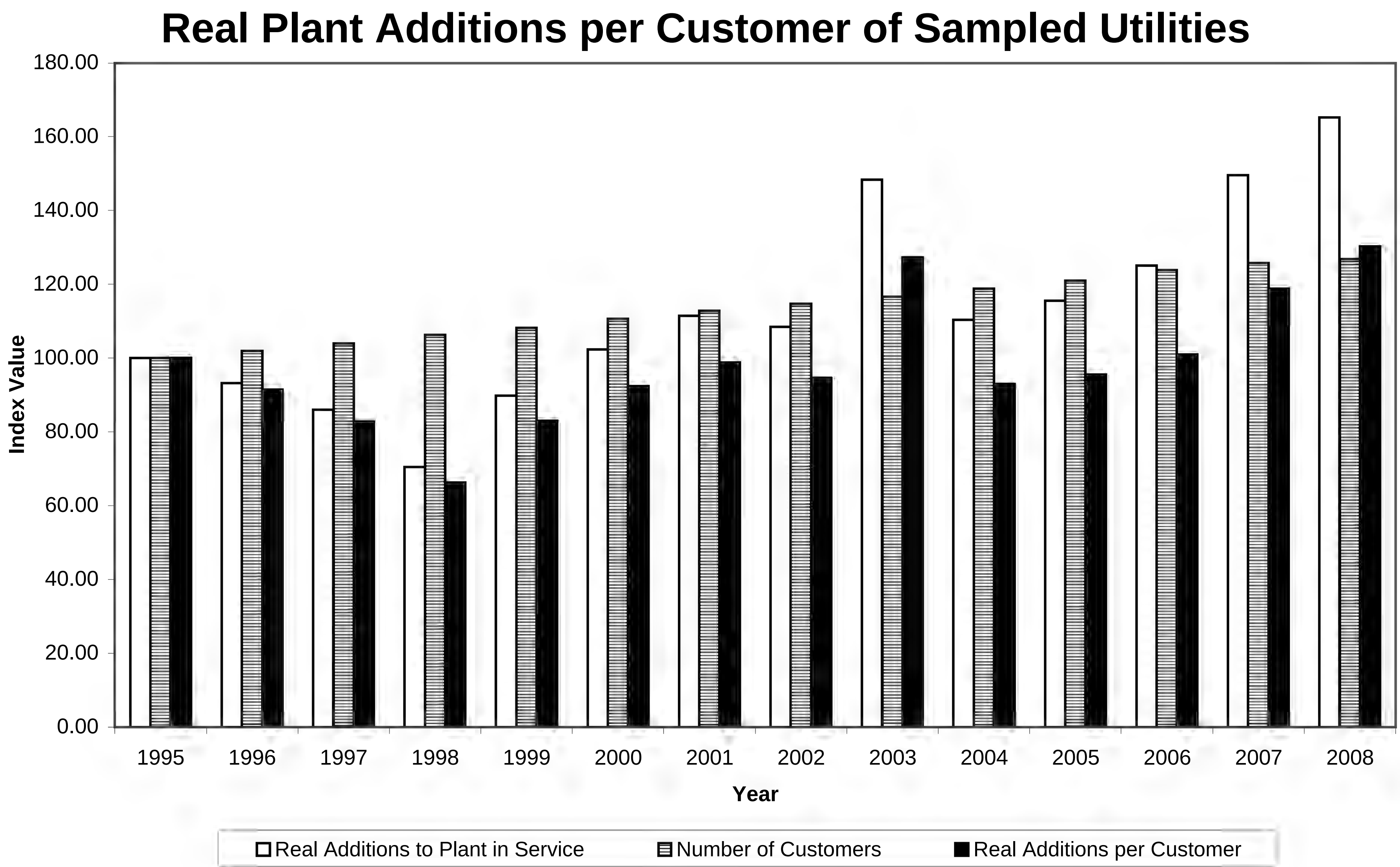

Real Plant Additions per Customer of Sampled Utilities
180.00
160.00
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Index Value
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
Year
Real Additions to Plant in Service
Number of Customers
Real Additions per Customer

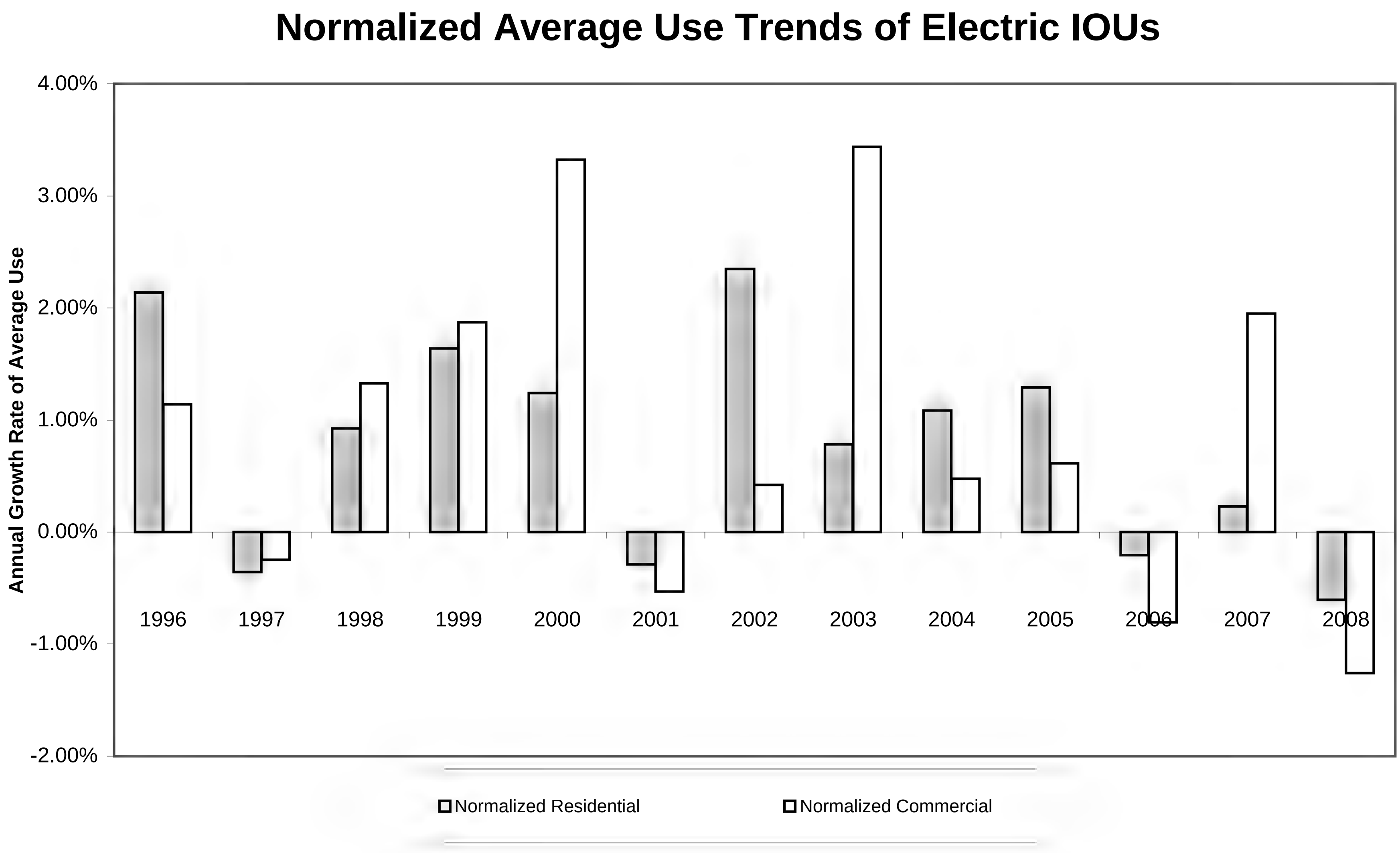
Table 7

Trends in Average Use by Residential & Commercial Customers of Investor-Owned Electric Utilities

	Residential		Commercial	
Year	Raw	Normalized	Raw	Normalized
1996	1.10%	2.14%	0.68%	1.14%
1997	-2.35%	-0.36%	-0.43%	-0.25%
1998	1.39%	0.93%	1.91%	1.33%
1999	1.66%	1.64%	1.63%	1.87%
2000	2.02%	1.24%	3.20%	3.33%
2001	-0.65%	-0.29%	-0.35%	-0.53%
2002	4.18%	2.35%	0.71%	0.42%
2003	-0.71%	0.78%	2.88%	3.44%
2004	0.03%	1.08%	0.35%	0.48%
2005	4.02%	1.29%	1.24%	0.61%
2006	-2.86%	-0.21%	-1.06%	-0.80%
2007	2.68%	0.23%	2.26%	1.95%
2008	-1.95%	-0.61%	-1.83%	-1.26%
Average Annual Growth Rate				
1996-2008	**0.66%**	**0.79%**	**0.86%**	**0.90%**
1996-2002	**1.05%**	**1.09%**	**1.05%**	**1.04%**
2003-2008	**0.20%**	**0.43%**	**0.64%**	**0.74%**
2006-2008	**-0.71%**	**-0.19%**	**-0.21%**	**-0.04%**
High DSM utilities	**-1.07%**	**-0.68%**	**-0.19%**	**-0.08%**
Other utilities	**-0.54%**	**0.05%**	**-0.22%**	**-0.02%**

Sources: Customer data from FERC Form 1. Volume data from Form EIA 861. Volumes were weather normalized by PEG Research using econometric demand modelling.

Figure 5


Normalized Average Use Trends of Electric IOUs
Annual Growth Rate of Average Use
4.00%
3.00%
2.00%
1.00%
0.00%
-1.00%
-2.00%
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
Normalized Residential
Normalized Commercial

3.2 HOW TEST YEARS AFFECT CREDIT QUALITY METRICS

Table 8 presents results for selected credit quality metrics for a large sample of electric utilities. The reported metrics are averages for the 2006-2009 period. The source is *Credit Stats: Electric Utilities—U.S.*, a report appearing in the Global Credit Portal of Standard & Poor's RatingsDirect. We present results for four credit metrics: Standard & Poor's corporate credit rating, the (rate of) return on capital, and two cash flow ratios (EBITDA interest coverage and FFO/Debt).

Cash flow ratios are used by credit analysts to assess a utility's ability to service debt. The cash flow measures are normally calculated as adjustments to net income that add back cash flows that could be used to service debt. FFO (funds from operations), for instance, adds back depreciation and amortization expenses. EBITDA (earnings before interest, taxes, depreciation, and amortization) adds back interest and tax payments as well as depreciation and amortization.

Table 8 reports averages for each of the numerical metrics for utilities that operated under historical, hybrid, and forward test years throughout the 2006-2008 period. There is also an indeterminate category for utilities that are not easily categorized as having operated under one kind of test year during this period.

Caution must be taken in making comparisons inasmuch as these metrics may differ between the sampled utilities due to differences in several other business conditions as well as to any differences in test years. The other relevant business conditions include the ability to rate base construction work in progress, the local severity of the 2008 recession, and whether or not utilities operated under formula rates and/or revenue decoupling. Despite these complications, the samples are large and diverse enough to shed some light on the effect that test years have on credit metrics.

Comparing the results, it can be seen that the values of all four credit metrics were typically much more favorable for the *forward* test year utilities than for the *historical* test year utilities.

- The forward test year utilities had a typical credit rating between BBB+ and A- whereas the historical test year utilities had a typical credit rating between BBB- and BBB.

Table 8

How Credit Metrics of Electric Utilities Differ by Test Year, 2006-2008

Company Name	S&P Corporate Credit Rating	Return on Capital (%)	EBITDA/Interest Coverage	FFO/debt (%)
Historical Test Years		**7.9**	**4.2**	**18.2**
AEP Texas Central	BBB	6.9	2.8	8.7
AEP Texas North	BBB	8.1	4.9	21.0
Appalachian Power	BBB	6.0	2.9	9.5
Arizona Public Service	BBB-	7.3	4.6	19.3
Black Hills Power	BBB-	9.6	4.8	25.3
Carolina Power & Light	BBB+	11.3	5.9	25.0
CenterPoint Energy Houston Electric	BBB	9.8	6.2	24.4
Central Illinois Light	BBB-	9.5	8.2	29.5
Central Illinois Public Service	BBB-	4.9	3.6	15.7
Central Vermont Public Service	BB+	7.0	2.7	12.8
Commonwealth Edison	BBB-	6.4	3.1	12.1
Duke Energy Carolinas	A-	7.0	6.1	28.5
Duke Energy Indiana	A-	8.0	5.1	21.3
El Paso Electric	BBB	9.4	4.2	18.8
Entergy Gulf States	BBB	7.2	2.8	25.1
Entergy Louisiana	BBB	6.6	3.2	36.3
Entergy Texas	BBB	5.6	2.5	14.0
Interstate Power & Light	BBB+	10.5	5.5	24.4
IPALCO Enterprises (Indianapolis Power & Light)	BB+	13.2	3.4	12.9
Kentucky Power	BBB	6.5	3.5	13.8
MidAmerican Energy	A-	10.7	5.5	22.7
Nevada Power	BB	8.4	2.6	11.1
NSTAR Electric	A+	10.2	7.7	21.6
Oklahoma Gas & Electric	BBB+	10.0	6.4	25.2
Oncor Electric Delivery	BBB+	9.6	4.4	17.9
Public Service Company of Colorado	BBB+	8.1	4.3	19.6
Public Service Company of New Hampshire	BBB	8.4	4.8	13.7
Public Service Company of New Mexico	BB-	3.9	2.3	8.6
Public Service Company of Oklahoma	BBB	4.9	2.7	18.3
Puget Sound Energy	BBB	7.5	3.8	13.7
Sierra Pacific Power	BB	7.4	2.9	12.7
South Carolina Electric & Gas	BBB+	8.3	4.7	21.1
Southern Indiana Gas & Electric	A-	9.5	5.4	22.8
Southwestern Electric Power	BBB	7.4	3.5	15.4
Southwestern Public Service	BBB+	5.3	3.5	12.1
Texas-New Mexico Power	BB-	5.3	3.3	9.5
Tuscon Electric Power	BB+	8.4	3.2	17.9
Westar Energy	BBB-	6.7	3.9	14.8
Western Massachusetts Electric	BBB	5.8	3.7	11.8
Hybrid Test Years		**9.5**	**5.9**	**19.9**
Atlantic City Electric	BBB	9.6	4.4	34.2
Baltimore Gas & Electric	BBB	6.8	4.3	11.1
Cleveland Electric Illuminating	BBB	13.3	4.3	9.2
Cleco Power	BBB	8.3	3.7	10.9
Columbus Southern Power	BBB	13.5	6.5	23.3
Dayton Power & Light	A-	16.3	16.1	42.9
Duke Energy Ohio	A-	5.2	6.3	25.5
Entergy Arkansas	BBB	6.7	5.6	27.7
Idaho Power	BBB	6.6	3.8	10.7
Jersey Central Power & Light	BBB	8.3	8.5	22.9
Metropolitan Edison	BBB	9.3	6.7	12.7
Ohio Edison	BBB	9.4	4.6	14.5
Ohio Power	BBB	8.2	4.3	15.0
PECO Energy	BBB	10.5	7.0	19.5
Pennsylvania Electric	BBB	8.9	5.5	15.8
PPL Electric Utilities	A-	9.5	4.6	18.6
Public Service Electric & Gas	BBB	8.7	4.9	14.9
Toledo Edison	BBB	11.9	5.2	28.0

Table 8, continued

How Credit Metrics of Electric Utilities Differ by Test Year, 2006-2008

Company Name	S&P Corporate Credit Rating	Return on Capital (%)	EBITDA/Interest Coverage	FFO/debt (%)
Forward Test Years		**9.2**	**5.1**	**21.0**
ALLETE (Minnesota Power)	BBB+	10.8	5.1	19.5
Central Hudson Gas & Electric	A	9.6	4.9	14.9
Central Maine Power	BBB+	8.2	5.3	17.8
Connecticut Light & Power	BBB	6.7	4.3	12.2
Detroit Edison	BBB	8.2	4.9	16.8
Entergy Mississippi	BBB	7.2	4.3	27.1
Florida Power & Light	A	9.9	7.0	30.7
Florida Power Corp.	BBB+	9.9	4.5	19.0
Georgia Power	A	10.1	5.9	22.6
Gulf Power	A	9.7	5.6	19.2
Hawaiian Electric	BBB	7.1	4.4	15.3
Mississippi Power	A	11.6	8.9	35.5
Northern States Power - MN	BBB+	9.4	4.9	22.9
Northern States Power - WI	A-	8.8	5.9	26.6
Pacific Gas & Electric	BBB+	10.7	4.0	23.3
PacifiCorp	A-	7.9	4.0	17.3
Portland General Electric	BBB+	7.9	4.1	19.2
Rochester Gas & Electric	BBB	9.4	3.8	19.4
Southern California Edison	BBB+	11.4	4.0	19.3
Tampa Electric	BBB	9.6	4.5	21.0
Wisconsin Electric Power	A-	6.9	5.4	14.6
Wisconsin Power & Light	A-	10.1	5.0	24.7
Wisconsin Public Service	A-	9.8	5.6	23.8
Indeterminate		**7.8**	**4.3**	**18.1**
Alabama Power	A	9.5	5.7	21.5
Empire District Electric	BBB-	7.3	3.5	15.7
Indiana Michigan Power	BBB	6.7	3.5	15.4
Kansas City Power & Light	BBB	7.9	4.8	19.4
Potomac Electric	BBB	7.4	4.4	20.6
Southwestern Electric Power	BBB	7.4	3.5	15.4
Union Electric	BBB-	8.2	4.4	18.4
All Companies		**8.6**	**4.8**	**19.3**

Source: Standard & Poor's Ratings Direct, *Credit Stats: Electric Utilities - U.S.* August 24, 2009. Financial metrics are averages of the years 2006-2008.

- The forward test year utilities had an average return on capital of 9.2% whereas the historical test year utilities had an average return of 7.9%.
- The forward test year utilities had an average EBITDA/interest coverage of 5.1 whereas the historical test year utilities had an average coverage of 4.2
- The forward test year utilities had an average FFO/debt ratio of 21.0% whereas the historical test year utilities had an average ratio of 18.2%.

Additional insights concerning the effect of forward test years on credit quality can be found in another recent Standard & Poor's report.[49] The study sought to rank state regulatory regimes with respect to their effect on credit quality. Of the fourteen states covered by the study which had well-established forward test year traditions at the time of the study, the author found five to be "more credit supportive", six to be "credit supportive", only two to be "less credit supportive", and none to be "least credit supportive". In contrast, of the seventeen states covered by the study that had well-established historical test year conditions, only three were categorized as "more credit supportive", seven were categorized as "credit supportive", six were categorized as "less credit supportive" and one was categorized as "least credit supportive".

3.3 Incentive Impact of Forward Test Years

In Section 1.2.4 we noted that the incentive impact of forward test years has been an issue in some proceedings. We argued, based on our experience in the field of incentive regulation, that the incentive impact of forward and historical test years should be similar on balance. To test the hypothesis that the choice of a test year has no impact on operating efficiency, PEG Research measured the trends in the O&M expenses of a large group of VIEUs over the 1996-2008 sample period. O&M expenses are a better focus than the total cost of base rate inputs in such a study because some utilities had greater needs than others for major plant additions and these needs had little to do with the kind of test year in a jurisdiction. Differences in cost growth are due in part to differences in output growth, so we divided O&M expenses by three alternative output metrics: generation volumes, generation capacity, and the number of customers served. We calculated how the trends in the three cost metrics differed for utilities operating under three kinds of test years: historical, hybrid, and

[49] Todd Shipman, *Assessing U.S. Utility Regulatory Environments*, Standard & Poor's Ratings Direct, November 2008.

forward. If forward test years weaken operating efficiency, we would expect the growth in the cost metrics to be higher on average for the forward test year utilities.

Results of this exercise are reported in Table 9. It can be seen that, using all three cost metrics, the cost trends of the forward test year utilities were similar to --- and a little slower than --- those of the historical test year utilities and of the full utility sample. These results are consistent with the notion that there is no significant difference in the incentives to contain cost that are generated by future and historical test years.

Table 9

Trends in Unit Non-Fuel O&M Expenses by Test Year, 1996-2008

	Test Year Type			
	Historic	Partial	Forward	All
Cost/Customer	2.1%	2.0%	1.9%	2.2%
Cost/Generation Volume	2.2%	3.0%	1.4%	2.3%
Cost/Generation Capacity	1.9%	3.2%	1.3%	1.9%

Source: Federal Energy Regulatory Commission (FERC) Form 1 and Form EIA-876 data gathered by SNL Financial.

4. CONCLUDING REMARKS

Having established in some detail in the chapters above the financial stresses imposed on U.S. electric utilities by historical test years today, we provide in this chapter some concluding remarks on action plans for regulators who wish to move forward with sensible remedies.

4.1 Sensible First Steps

In states where regulators are interested in experimenting with forward test years but not yet prepared to "make the plunge" to large scale adoption, our discussion has identified a number of cautious first steps down the road that limit the risk of bad outcomes but permit the regulatory community to learn more about FTY pros and cons.

- Allow a forward test year on a trial basis for one interested utility.
- Allow forward test years on an occasional basis when a utility makes a convincing case that rising unit costs make historical test years unjust and unreasonable. A ruling on the test year issue can precede the preparation of a rate case, as in Utah.
- Borrow a few of the methods used in FTY rate cases to make additional adjustments to *historical* test year costs and billing determinants. For example, HTY O&M expenses and/or plant addition costs can be adjusted for forecasts of price inflation prepared by respected independent agencies. Residential and commercial delivery volumes can be adjusted for recent average use trends. Special adjustments can be made for looming major plant additions.
- Try current FTYs, which involve forecasts only one year into the future. Current test years can be combined with interim rate increases at the outset a rate case which are subject to true up when new rates are ultimately approved. The combination of current test years and interim rates is a salient option because it eliminates regulatory lag without a two year forecast.

4.2 Alternative Remedies for Test Year Attrition

In states where regulators aren't ready to abandon historical test years but are sympathetic to the attrition problems that they sometimes cause, a variety of alternative measures are available to relieve the financial attrition that can result from using historical test years in a rising unit cost environment.

1. HTY calculations can incorporate the full array of normalization, annualization, and known and measurable change adjustments that are used in other jurisdictions.
2. Utilities can be permitted to implement interim rate increases. Interim rates can effectively reduce regulatory lag by a year. States that permit interim rates include HI, IA, MI, MO, NH, OK, TX, VA, and WI.
3. Capital spending trackers can ensure timely commencement of the recovery of costs of plant additions, without rate cases, when assets become used and useful. Trackers can be designed to maintain incentives for good capital cost management and timely project completion. Monitoring by PEG Research reveals that capital spending trackers have been approved for use by energy utilities in AR, CA, FL, GA, IA, ID, IL, IN, KS, KY, MD, ME, MN, MO, NJ, NY, OH, OK, OR, PA, TX, VA, and WI.
4. The inclusion of CWIP in rate base improves cash flow and reduces future rate shocks. This practice also reduces the losses that a utility experiences making large plant additions under historical test year rates. Monitoring by the Edison Electric Institute has found that states that have recently allowed inclusion of CWIP in rate base include CO, FL, GA, IN, KS, KY, LA, MI, MO, NC, NM, NV, SD, TN, VA, and WV.
5. Cost trackers can also adjust rates automatically to ensure timely recovery of O&M expenses that are unusually volatile and/or expected to rise rapidly. Expenses that are often recovered using trackers include those for pensions and benefits, uncollectible bills, and DSM.
6. Several methods have been established to compensate utilities for slowing growth in average use.
    - Lost revenue adjustment mechanisms (a/k/a lost margin trackers) restore margins that are estimated to have been lost because of utility conservation programs. These are currently used by electric utilities in CT, IN, KY, OH, NC, and SC.

- Decoupling true-up plans help base rate revenue track revenue requirements more closely and can thereby restore lost margins that result from slow growth in average use resulting from a wider variety of sources, including conservation programs administered by independent agencies. Such plans are currently used by electric utilities in CA, CT, DC, HI, ID, MA, MD, MI, NY, OR, VT, and WI. They are used by gas utilities in several additional states (*e.g.* AR, CO, IN, MN, NJ, NC, UT, VA, WA, and WY).
- Higher customer charges are also effective in reducing attrition from declining average use. Straight fixed variable pricing, which recovers *all* fixed costs using fixed charges, is used by gas utilities in GA, MO, OH, OK, and ND.

7. The duration of rate cases can be limited. A reasonable cap is the average length of cases in the United States, which is currently between nine and ten months.[50]
8. Multiyear rate plans can give utilities rate escalation between rate cases for inflation and other business conditions that drive cost growth. Such plans typically have a duration of three to five years, and terms of seven to ten years have been approved. Even if an historical test year makes the initial rates under such plans non-compensatory, it would only happen once in a multiyear period. Utilities would have several years to recoup their losses through superior productivity growth --- and an incentive to do so. North American jurisdictions where multiyear rate plans are common include CA, ME, MA, NY, OH, and VT in the United States and Alberta, British Columbia, and Ontario in Canada. This approach to ratemaking is more the rule than the exception overseas.

[50] See *EEI 2007 Financial Review*, p. 36.

APPENDIX: UNIT COST LOGIC

To better understand the conditions that can cause historical test year rates to produce earnings attrition, suppose that year t is a rate year (a year when new rates take effect) and that the utility is underearning with its newly implemented HTY rates. The cost of base rate inputs then exceeds base rate revenue and the ratio of cost to revenue is positive.

$$Cost_t / Revenue_t > 0.$$

To simplify the story, suppose next that the utility has only one service and the base rate for that service is gathered exclusively from a volumetric charge. In the historical test year, the revenue requirement is then the product of a price (P_{t-2}) and a volume (V_{t-2}) and this is set equal to the allowed cost of service

$$P_{t-2} \times V_{t-2} = Cost_{t-2}$$

so that

$$P_{t-2} = Cost_{t-2} / V_{t-2} = Unit\ Cost_{t-2}.$$

The rate equals the cost per kWh of sales, which we may call the *unit* cost of service in the historical test year.

Revenue in the rate year is the product of this same price, which reflects *historical* business conditions, and the *contemporary* sales volume. The ratio of cost to revenue may then be restated as

$$\begin{aligned} Cost_t / Revenue_t &= Cost_t / (P_{t-2} \times V_t) \\ &= Cost_t / [(Cost_{t-2} / V_{t-2}) \times V_t] \\ &= (Cost_t / V_t) / (Cost_{t-2} / V_{t-2}) \\ &= Unit\ Cost_t / Unit\ Cost_{t-2}. \end{aligned} \quad [A1]$$

An historical test year rate is thus non-compensatory if the utility's unit cost is higher in the rate year than it was two years ago in the test year. Growth in the unit cost of the utility is thus the fundamental reason for earnings attrition. Note also that

$$Unit\ Cost_t / Unit\ Cost_{t-2} = (Cost_t / Cost_{t-2}) / (V_t/V_{t-2}). \quad [A2]$$

Unit cost thus grows between the test year and the rate year if cost grows more rapidly than the sales volume. Growth in the sales volume therefore matters as well as cost growth in determining a utility's unit cost trend. Moreover, the ability of historical test year rates to avoid under or, for that matter, over earning depends on the stability of the relationship between cost and billing determinants.

The key result that historical test years are non-compensatory when unit cost is rising extends to the real world situation in which a utility provides multiple services, each with several charges. In this situation the ratio of the total delivery volume in [A2] is replaced by a weighted average of the ratios for all billing determinants.[51]

[51] The weight for each individual billing determinant is its share of the total base rate revenue.

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)**

OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2022
OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)**

OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ______ to ______

Commission file number 001-16189

NiSource Inc.
(Exact name of registrant as specified in its charter)

DE	35-2108964
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
801 East 86th Avenue Merrillville, IN	46410
(Address of principal executive offices)	(Zip Code)

(877) 647-5990
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	NI	NYSE
Depositary Shares, each representing a 1/1,000th ownership interest in a share of 6.50% Series B Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock, par value $0.01 per share, liquidation preference $25,000 per share and a 1/1,000th ownership interest in a share of Series B-1 Preferred Stock, par value $0.01 per share, liquidation preference $0.01 per share	NI PR B	NYSE
Series A Corporate Units	NIMC	NYSE

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).
Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definition of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12-b-2 of the Exchange Act.

Large accelerated filer ☑ Accelerated Filer ☐ Emerging Growth Company ☐ Non-accelerated Filer ☐ Smaller Reporting Company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☑

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrants included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240. 10D-1(b).☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of the registrant's common stock, par value $0.01 per share (the "Common Stock") held by non-affiliates was approximately $11,950,785,429 based upon the June 30, 2022, closing price of $29.49 on the New York Stock Exchange.

There were 412,507,944Āshares of Common Stock outstanding as of February 15, 2023.

<u>Documents Incorporated by Reference</u>

Part III of this report incorporates by reference specific portions of the Registrant’s Notice of Annual Meeting and Proxy Statement relating to the Annual Meeting of Stockholders to be held on May 23, 2023.

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DEFINED TERMS

The following is a list of frequently used abbreviations or acronyms that are found in this report:

NiSource Subsidiaries and Affiliates

Columbia of Kentucky	Columbia Gas of Kentucky, Inc.
Columbia of Maryland	Columbia Gas of Maryland, Inc.
Columbia of Massachusetts	Bay State Gas Company
Columbia of Ohio	Columbia Gas of Ohio, Inc.
Columbia of Pennsylvania	Columbia Gas of Pennsylvania, Inc.
Columbia of Virginia	Columbia Gas of Virginia, Inc.
NIPSCO	Northern Indiana Public Service Company LLC
NiSource ("we," "us" or "our")	NiSource Inc.
Rosewater	Rosewater Wind Generation LLC and its wholly owned subsidiary, Rosewater Wind Farm LLC
Indiana Crossroads Wind	Indiana Crossroads Wind Generation LLC and its wholly owned subsidiary, Indiana Crossroads Wind Farm LLC

Abbreviations and Other

AFUDC	Allowance for funds used during construction
AOCI	Accumulated Other Comprehensive Income (Loss)
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
ATM	At-the-market
BTA	Build-transfer agreement
CAP	Compliance Assurance Process
CCGT	Combined Cycle Gas Turbine
CCRs	Coal Combustion Residuals
CEP	Capital Expenditure Program
CERCLA	Comprehensive Environmental Response Compensation and Liability Act (also known as Superfund)
Corporate Units	Series A Corporate Units
COVID-19 ("the COVID-19 pandemic" or "the pandemic")	Novel Coronavirus 2019 and its variants, including the Delta and Omicron variants, and any other variant that may emerge
DE&I	Diversity Equity and Inclusion
DPU	Department of Public Utilities
DSM	Demand Side Management
EPA	United States Environmental Protection Agency
EPS	Earnings per share
Equity Units	Series A Equity Units
FAC	Fuel adjustment clause
FERC	Federal Energy Regulatory Commission
FMCA	Federally Mandated Cost Adjustment
GAAP	Generally Accepted Accounting Principles
GCA	Gas cost adjustment
GHG	Greenhouse gases
HLBV	Hypothetical Liquidation at Book Value
IRA	Inflation Reduction Act
IRP	Infrastructure Replacement Program
IRS	Internal Revenue Service

DEFINED TERMS

IURC	Indiana Utility Regulatory Commission
JV	Joint Venture
LDCs	Local distribution companies
LIBOR	London InterBank Offered Rate
LIFO	Last-in, first-out
LIHEAP	Low Income Heating Energy Assistance Programs
Massachusetts Business	All of the assets sold to, and liabilities assumed by, Eversource pursuant to the Asset Purchase Agreement
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator
MMDth	Million dekatherms
MW	Megawatts
MWh	Megawatt hours
NOL	Net Operating Loss
NTSB	National Transportation Safety Board
NYMEX	The New York Mercantile Exchange
OPEB	Other Postretirement and Postemployment Benefits
PCB	Polychlorinated biphenyls
PHMSA	Pipeline and Hazardous Materials Safety Administration
PPA	Power Purchase Agreement
PSC	Public Service Commission
PUC	Public Utilities Commission
ROE	Return on Equity
ROU	Right of Use
SAVE	Steps to Advance Virginia's Energy Plan
Scope 1 GHG Emissions	Direct emissions from sources owned or controlled by us (e.g., emissions from our combustion of fuel, vehicles, and process emissions and fugitive emissions)
Scope 2 GHG Emissions	Indirect emissions from sources owned or controlled by us
SEC	Securities and Exchange Commission
SMRP	Safety Modification and Replacement Program
SMS	Safety Management System
STRIDE	Strategic Infrastructure Development and Enhancement
TCJA	An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018 (commonly known as the Tax Cuts and Jobs Act of 2017)
TDSIC	Transmission, Distribution and Storage System Improvement Charge
U.S. Attorney's Office	U.S. Attorney's Office for the District of Massachusetts
VIE	Variable Interest Entity

Note regarding forward-looking statements

This Annual Report on Form 10-K contains "forward-looking statements," within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Investors and prospective investors should understand that many factors govern whether any forward-looking statement contained herein will be or can be realized. Any one of those factors could cause actual results to differ materially from those projected. These forward-looking statements include, but are not limited to, statements concerning our plans, strategies, objectives, expected performance, expenditures, recovery of expenditures through rates, stated on either a consolidated or segment basis, and any and all underlying assumptions and other statements that are other than statements of historical fact. Expressions of future goals and expectations and similar expressions, including "may," "will," "should," "could," "would," "aims," "seeks," "expects," "plans," "anticipates," "intends," "believes," "estimates," "predicts," "potential," "targets," "forecast," and "continue," reflecting something other than historical fact are intended to identify forward-looking statements. All forward-looking statements are based on assumptions that management believes to be reasonable; however, there can be no assurance that actual results will not differ materially.

Factors that could cause actual results to differ materially from the projections, forecasts, estimates and expectations discussed in this Annual Report on Form 10-K include, among other things, our ability to execute our business plan or growth strategy, including utility infrastructure investments; potential incidents and other operating risks associated with our business; our ability to adapt to, and manage costs related to, advances in technology; impacts related to our aging infrastructure; our ability to obtain sufficient insurance coverage and whether such coverage will protect us against significant losses; the success of our electric generation strategy; construction risks and natural gas costs and supply risks; fluctuations in demand from residential and commercial customers; fluctuations in the price of energy commodities and related transportation costs or an inability to obtain an adequate, reliable and cost-effective fuel supply to meet customer demands; the attraction and retention of a qualified, diverse workforce and ability to maintain good labor relations; our ability to manage new initiatives and organizational changes; the actions of activist stockholders; the performance of third-party suppliers and service providers; potential cybersecurity attacks; increased requirements and costs related to cybersecurity; any damage to our reputation; any remaining liabilities or impact related to the sale of the Massachusetts Business; the impacts of natural disasters, potential terrorist attacks or other catastrophic events; the physical impacts of climate change and the transition to a lower carbon future; our ability to manage the financial and operational risks related to achieving our carbon emission reduction goals, including our Net Zero Goal (as defined below); our debt obligations; any changes to our credit rating or the credit rating of certain of our subsidiaries; any adverse effects related to our equity units; adverse economic and capital market conditions or increases in interest rates; inflation; recessions; economic regulation and the impact of regulatory rate reviews; our ability to obtain expected financial or regulatory outcomes; continuing and potential future impacts from the COVID-19 pandemic; economic conditions in certain industries; the reliability of customers and suppliers to fulfill their payment and contractual obligations; the ability of our subsidiaries to generate cash; pension funding obligations; potential impairments of goodwill; the outcome of legal and regulatory proceedings, investigations, incidents, claims and litigation; potential remaining liabilities related to the Greater Lawrence Incident; compliance with the agreements entered into with the U.S. Attorney's Office to settle the U.S. Attorney's Office's investigation relating to the Greater Lawrence Incident; compliance with applicable laws, regulations and tariffs; compliance with environmental laws and the costs of associated liabilities; changes in taxation; and other matters set forth in Item 1, "Business," Item 1A, "Risk Factors" and Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," of this report, some of which risks are beyond our control. In addition, the relative contributions to profitability by each business segment, and the assumptions underlying the forward-looking statements relating thereto, may change over time.

All forward-looking statements are expressly qualified in their entirety by the foregoing cautionary statements. We undertake no obligation to, and expressly disclaim any such obligation to, update or revise any forward-looking statements to reflect changed assumptions, the occurrence of anticipated or unanticipated events or changes to the future results over time or otherwise, except as required by law.

PART I

ITEM 1. BUSINESS

NISOURCE INC.

NiSource Inc. is an energy holding company under the Public Utility Holding Company Act of 2005 whose primary subsidiaries are fully regulated natural gas and electric utility companies, serving approximately 3.7 million customers in six states. NiSource is the successor to an Indiana corporation organized in 1987 under the name of NIPSCO Industries, Inc., which changed its name to NiSource Inc. on April 14, 1999.

NiSource's principal subsidiaries include NiSource Gas Distribution Group, Inc., a natural gas distribution holding company, and NIPSCO, a gas and electric company. NiSource derives substantially all of its revenues and earnings from the operating results of these rate-regulated businesses.

Business Strategy

We focus our business strategy on providing safe and reliable service through our core, rate-regulated asset-based utilities, with the goal of adding value to all stakeholders. Our utilities continue to make progress on core safety, infrastructure and environmental investment programs supported by complementary regulatory and customer initiatives across all six states in which we operate. Our goal is to develop strategies that benefit all stakeholders as we (i) embark on long-term infrastructure investment and safety programs to better serve our customers, (ii) align our tariff structures with our cost structure, and (iii) address changing customer conservation patterns. These strategies focus on improving safety and reliability, enhancing customer service, pursuing regulatory and legislative initiatives to increase accessibility for customers currently not on our gas and electric service, ensuring customer affordability and reducing emissions while generating sustainable returns.

NiSource remains committed to the advancement of our SMS for the safety of our customers, communities and employees. Our SMS is the established operating model within NiSource. In 2022, NiSource achieved conformance certification to the American Petroleum Institute Recommended Practice 1173, which serves as the guiding practice for our SMS. This certification marks an important milestone for our SMS and NiSource's journey towards operational excellence. Moving forward, our focus shifts to maintaining, sustaining and continuously improving the process, procedures, capabilities and talent to enhance safety and reduce operational risk. Additionally, we continue to pursue regulatory and legislative initiatives that will allow customers not currently on our system to obtain gas and electric service in a cost effective manner.

NiSource has two reportable segments: Gas Distribution Operations and Electric Operations. The remainder of our operations, which are not significant enough on a stand-alone basis to warrant treatment as an operating segment, are included as Corporate and Other. The activities occurring within this non-segment consist of our centralized financing and treasury activities and are primarily comprised of interest expense on holding company debt and unallocated corporate costs and activities. The following is a summary of the business for each reporting segment. Refer to Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 21, "Business Segment Information," in the Notes to Consolidated Financial Statements for additional information related to each segment.

Gas Distribution Operations

Our natural gas distribution operations serve approximately 3.3 million customers in six states. Through our wholly-owned subsidiary NiSource Gas Distribution Group, Inc., we own five distribution subsidiaries that provide natural gas to approximately 2.4 million residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, and Maryland. Additionally, we distribute natural gas to approximately 859,000 customers in northern Indiana through our wholly-owned subsidiary NIPSCO. We operate approximately 54,800 miles of distribution main pipeline plus the associated individual customer service lines and 1,000 miles of transmission main pipeline located in our service areas described below. Throughout our service areas we also have gate stations and other operations support facilities.

Competition. Open access to natural gas supplies over interstate pipelines and the deregulation of the natural gas supply has led to tremendous change in the energy markets and natural gas competition. Due to open access to natural gas supplies, LDC customers can purchase gas directly from producers and marketers in an open, competitive market. This separation or "unbundling" of the transportation and other services offered by LDCs allows customers to purchase the commodity independent of services provided by LDCs. LDCs continue to purchase gas and recover the associated costs from their customers. Certain of our Gas Distribution Operations' subsidiaries are involved in programs that provide our residential and commercial customers the opportunity to purchase their natural gas requirements from third parties and use our Gas Distribution Operations' subsidiaries for transportation services. As of December 31, 2022, 24.5% of our residential customers and 33.3% of our commercial customers participated in such programs.

Gas Distribution Operations competes with (i) investor-owned, municipal, and cooperative electric utilities throughout its service areas, (ii) other regulated and unregulated natural gas intra and interstate pipelines and (iii) other alternate fuels, such as propane and fuel oil. Gas Distribution Operations continues to be a strong competitor in the energy market as a result of strong customer preference for natural gas. Competition with providers of electricity has traditionally been the strongest in the residential and commercial markets of Kentucky, southern Ohio, central Pennsylvania and western Virginia due to comparatively low electric rates.

Additionally, our gas distribution operations are subject to seasonal fluctuations in sales. Revenues from gas distribution operations are more significant during the heating season, which is primarily from November through March. Please refer to Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - Results and Discussion of Segment Operations - Gas Distribution Operations," for additional information.

Electric Operations

We generate, transmit and distribute electricity through our subsidiary NIPSCO to approximately 486,000 customers in 20 counties in the northern part of Indiana and also engage in wholesale electric and transmission transactions. We own and operate sources of generation as well as source power through PPAs. We continue to transition our generation portfolio to primarily renewable sources. During 2021, we operated Rosewater for the full year, Indiana Crossroads Wind went into service during December 2021, and in December of 2022 we closed on the Indiana Crossroads Solar project, which is expected to go into service in 2023. In October 2021, NIPSCO completed the retirement of two coal-burning units with installed capacity of approximately 903 MW at Schahfer Generating Station, located in Wheatfield, IN. We also purchased energy generated from renewable sources through PPAs in 2022. As of December 31, 2022 we have multiple PPAs that provide 500 MW of capacity, with contracts expiring between 2024 and 2040. See below for information on our owned operating facilities:

Facility Name	Location	Fuel Type	Generating Capacity (MW)(1)
R.M. Schahfer	Wheatfield, IN	Steam - Coal	722
Michigan City	Michigan City, IN	Steam - Coal	455
Sugar Creek	West Terre Haute, IN	CCGT	563
R.M. Schahfer	Wheatfield, IN	Natural Gas	155
Oakdale	Carroll County, IN	Hydro	9
Norway	White County, IN	Hydro	7
Rosewater Wind Generation LLC(2)	White County, IN	Wind	102
Indiana Crossroads Wind Generation LLC(2)	White County, IN	Wind	302
Total MW Capacity			2,315

(1)Represents current net generating capability of each fossil fuel and hydro generating unit. Nameplate capacity is listed for wind generating units.
(2)NIPSCO is the managing partner of these JVs. Refer to Note 4, "Variable Interest Entities," in the Notes to Consolidated Financial Statements for more information.

In November 2021, NIPSCO submitted its 2021 Integrated Resource Plan ("2021 Plan") with the IURC. The 2021 plan builds upon the 2018 Integrated Resource Plan which outlined NIPSCO's plan to retire its coal generating assets by 2028. The 2021 plan affirmed the 2018 retirement decisions and calls for the replacement of the retiring units with a diverse portfolio of resources including demand side management resources, modest amounts of incremental solar, stand-alone energy storage, new gas peaking resources and upgrades to existing facilities at the Sugar Creek Generating Station, among other steps. Refer to Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for further discussion of these plans.

NIPSCO's transmission system, with voltages from 69,000 to 765,000 volts, consists of 3,016 circuit miles. NIPSCO is interconnected with eight neighboring electric utilities.

NIPSCO participates in the MISO transmission service and wholesale energy market. MISO is a nonprofit organization created in compliance with FERC regulations to improve the flow of electricity in the regional marketplace and to enhance electric reliability. Additionally, MISO is responsible for managing energy markets, transmission constraints and the day-ahead, real-time, Financial Transmission Rights and ancillary markets. NIPSCO has transferred functional control of its electric transmission assets to MISO, and transmission service for NIPSCO occurs under the MISO Open Access Transmission Tariff. NIPSCO generating units are dispatched by MISO which takes into account economics, reliability of the MISO system and unit availability. During the year ended December 31, 2022, NIPSCO generating units were dispatched to meet 41.65% of its load requirements, and NIPSCO purchased 58.35% from the MISO market.

NISOURCE INC.

Competition. Our electric utilities generally have exclusive service areas under Indiana regulations, and retail electric customers in Indiana do not have the ability to choose their electric supplier. NIPSCO faces non-utility competition from other energy sources, such as self-generation by large industrial customers and other distributed energy sources.

Our electric operations are subject to seasonal fluctuations in sales. Revenues from electric operations are more significant during the cooling season, which is primarily from June through September. Please refer to Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - Results and Discussion of Segment Operations - Electric Operations," for additional information.

Political Action

The NiSource Political Action Committee ("NiPAC") provides our employees a voice in the political process. NiPAC is a voluntary, employee and director driven and funded political action committee, and NiPAC makes bipartisan political contributions to local, state and federal candidates, where permitted and in accordance with established guidelines. Consistent with our commitments and our approach to engagement, the NiPAC leadership committee members evaluate candidates for support on issues important to our business.

Regulatory

The regulatory landscape applicable to our operations, including environmental regulations, at both the state and federal levels, continue to evolve. These changes have had and will continue to have an impact on our operations, structure and profitability. Management continually seeks new ways to be more competitive and profitable in this environment, while keeping service and affordability for customers at the forefront. We believe we are, in all material respects, in compliance with such laws and regulations and do not expect continued compliance to have a material impact on our capital expenditures, earnings, or competitive position. We continue to monitor existing and pending laws and regulations, and the impact of regulatory changes cannot be predicted with certainty.

Rate Case Actions. The following table describes current rate case actions as applicable in each of our jurisdictions net of tracker impacts. See "Cost Recovery and Trackers" below for further detail on trackers.

(in millions)

Company	Proposed ROE	Approved ROE	Requested Incremental Revenue	Approved Incremental Revenue	Filed	Status	Rates Effective
Currently Approved in Current or Future Rates							
Columbia of Pennsylvania[1]	10.95 %	None specified	$ 82.2	$ 44.5	March 18, 2022	Approved December 8, 2022	December 2022
Columbia of Maryland	10.85 %	9.65 %	$ 5.8	$ 3.5	May 13, 2022	Approved November 17, 2022	December 2022
Columbia of Kentucky[2]	10.30 %	9.35 %	$ 26.7	$ 18.3	May 28, 2021	Approved December 28, 2021	January 2022
Columbia of Virginia[3]	10.95 %	None specified	$ 14.2	$ 1.3	August 28, 2018	Approved June 12, 2019	February 2019
Columbia of Ohio	10.95 %	9.60 %	$ 221.4	$ 68.2	June 30, 2021	Approved January 26, 2023	March 2023
NIPSCO - Gas[4]	10.50 %	9.85 %	$ 109.7	$ 71.8	September 29, 2021	Approved July 27, 2022	September 2022
NIPSCO - Electric	10.80 %	9.75 %	$ 21.4	$ (53.5)	October 31, 2018	Approved December 4, 2019	January 2020
Active Rate Cases							
Columbia of Virginia[5]	10.75 %	In process	$ 40.6	In process	April 29, 2022	Order Expected Q1 2023	Interim Rates October 2022
NIPSCO - Electric[6]	10.40 %	In process	$ 291.8	In process	September 19, 2022	Order Expected Q3 2023	September 2023

[1] No approved ROE is identified for this matter since the approved revenue increase is the result of a black box settlement under which parties agree upon the amount of increase.
[2]The approved ROE for natural gas capital riders (*e.g.*,SMRP) is 9.275%.
[3]Columbia of Virginia's rate case resulted in a black box settlement, representing a settlement to a specific revenue increase but not a specified ROE. The settlement provides use of a 9.70% ROE for future SAVE filings.
[4]New rates are implemented in 2 steps, with implementation of Step 1 rates in September 2022. The Step 2 rates were filed on February 21, 2023, with rates effective March 2023.
[5] Beginning October 2022, interim rates are being billed subject to refund, pending a final commission order. On December 9, 2022, a Stipulation and Proposed Recommendation was filed with the Virginia State Corporation Commission recommending approval of $25.8 million of incremental revenue.
[6]New rates will be implemented in 2 steps, with implementation of Step 1 rates to be effective in September 2023 and Step 2 rates to be effective in March 2024. On February 16, 2023, NIPSCO filed rebuttal updating the requested revenue requirement to $279.2 million.

NISOURCE INC.

FERC. NiSource's service companies and operating companies are subject to varying degrees of regulation by the FERC. NiSource Corporate Services files a FERC Form 60 annual report with its financial information as a FERC jurisdictional centralized service company. NiSource also files an annual FERC Form 61 which contains a narrative description of the service company's functions during the prior calendar year.

As natural gas LDCs, Columbia of Maryland and Columbia of Ohio have limited jurisdictional certificates to transport gas in the respective service territories into interstate commerce. NIPSCO and Columbia of Pennsylvania currently have applications pending at FERC for limited jurisdictional certificates.

As an electric company, NIPSCO has Market Based Rate authority and is a Transmission Owner subject to FERC jurisdiction. NIPSCO files the following reports annually: FERC Form 1, which is a comprehensive financial and operating report, FERC Form 566, which is a list of its 20 largest purchases of electricity over the past three years; FERC Form 715, which is its Annual Transmission Planning and Evaluation Report and the base case power flow data from the Eastern Interconnection Reliability Assessment Group Multiregional Modeling Working Group, which was used by NIPSCO for transmission planning; and FERC Form 730, which is NIPSCO's Report of Transmission Investment Activity. As a Transmission Owner subject to the MISO Transmission Owners Agreement and Tariff, NIPSCO has various FERC jurisdictional obligations such as maintaining its Attachment O formula rates and corresponding protocols. NIPSCO also has FERC approvals to make affiliate transactions between itself and various JVs. NIPSCO's officers, on the electric side, are also subject to FERC's interlocking directorate rules and reporting requirements.

Regulatory Framework. The Gas Distribution Operations utilities have pursued non-traditional revenue sources within the evolving natural gas marketplace. These efforts include (i) the sale of products and services in the companies' service territories, and (ii) gas supply cost incentive mechanisms for service to their core markets. The on-system services are offered by us to customers and include products such as the transportation and balancing of gas on the Gas Distribution Operations utility's system. The incentive mechanisms give the Gas Distribution Operations utilities an opportunity to share in the savings created from such situations as gas purchase prices paid below an agreed upon benchmark and their ability to reduce pipeline capacity charges with their customers.

We recognize that energy efficiency reduces emissions, conserves natural resources and saves our customers money. Our gas distribution companies offer programs such as energy efficiency upgrades, home checkups and weatherization services. The increased efficiency of natural gas appliances and improvements in home building codes and standards contributes to a long-term trend of declining average use per customer. While we are looking to expand offerings so the energy efficiency programs can benefit as many customers as possible, our Gas Distribution Operations have pursued changes in rate design to more effectively match recoveries with costs incurred. Columbia of Ohio has adopted a straight fixed variable rate design that closely links the recovery of fixed costs with fixed charges. Columbia of Maryland and Columbia of Virginia have regulatory approval for weather and revenue normalization adjustments for certain customer classes, which adjust monthly revenues that exceed or fall short of approved levels. Columbia of Pennsylvania continues to operate its pilot residential weather normalization adjustment and also has a fixed customer charge. This weather normalization adjustment only adjusts revenues when actual weather compared to normal varies by more than 3%. Columbia of Kentucky incorporates a weather normalization adjustment for certain customer classes and also has a fixed customer charge. In a prior gas base rate proceeding, NIPSCO implemented a higher fixed customer charge for residential and small customer classes moving toward recovering more of its fixed costs through a fixed recovery charge, but has no weather or usage protection mechanism.

While increased efficiency of electric appliances and improvements in home building codes and standards has similarly impacted the average use per electric customer in recent years, NIPSCO expects future growth in per customer usage as a result of increasing electric applications. Further growth is anticipated as electric vehicles become more prevalent. These ongoing changes in use of electricity will likely lead to development of innovative rate designs, and NIPSCO will continue efforts to design rates that increase the certainty of recovery of fixed costs.

Cost Recovery and Trackers. Comparability of our line item operating results is impacted by regulatory trackers that allow for the recovery in rates of certain costs such as those described below. Increases in the expenses that are subject to approved regulatory tracker mechanisms generally lead to increased regulatory assets, which ultimately result in a corresponding increase in operating revenues and, therefore, have essentially no impact on total operating income results. Certain approved regulatory tracker mechanisms allow for abbreviated regulatory proceedings in order for the operating companies to quickly implement revised rates and recover associated costs.

A portion of the Gas Distribution Operations revenue is related to the recovery of gas costs, the review and recovery of which occurs through standard regulatory proceedings. All states in our operating area require periodic review of actual gas procurement activity to determine prudence and confirm the recovery of prudently incurred energy commodity costs supplied to customers.

A portion of the Electric Operations revenue is related to the recovery of fuel costs to generate power and the fuel costs related to purchased power. These costs are recovered through a FAC, which is updated quarterly to reflect actual costs incurred to supply electricity to customers.

Environmental and Safety Matters

PHMSA Regulations
On December 27, 2020, the Protecting Our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act of 2020 was signed into law, reauthorizing funding for federal pipeline safety programs through September 30, 2023. Among other things, the PIPES Act requires that PHMSA revise the pipeline safety regulations to require operators to update, as needed, their existing distribution integrity management plans, emergency response plans, and operation and maintenance plans. The PIPES Act also requires PHMSA to adopt new requirements for managing records and updating, as necessary, existing district regulator stations to eliminate common modes of failure that can lead to overpressurization. PHMSA must also require that operators implement and utilize advanced leak detection and repair technologies that enable the location and categorization of all leaks that are hazardous, or potentially hazardous, to human safety or the environment. Natural gas companies, including NiSource and our subsidiaries, may see increased costs depending on how PHMSA implements the new mandates resulting from the PIPES Act.

Climate Change Issues
Physical Climate Risks. Increased frequency of severe and extreme weather events associated with climate change could materially impact our facilities, energy sales, and results of operations. We are unable to predict these events. However, we perform ongoing assessments of physical risk, including physical climate risk, to our business. More extreme and volatile temperatures, increased storm intensity and flooding, and more volatile precipitation leading to changes in lake and river levels are among the weather events that are most likely to impact our business. Efforts to mitigate these physical risks continue to be implemented on an ongoing basis.

Transition Climate Risks. Future legislative and regulatory programs, at both the federal and state levels, could significantly limit allowed GHG emissions or impose a cost or tax on GHG emissions. Revised or additional future GHG legislation and/or regulation related to the generation of electricity or the extraction, production, distribution, transmission, storage and end use of natural gas could materially impact our gas supply, financial position, financial results and cash flows.

Regarding federal policies, we continue to monitor the implementation of any final and proposed climate change-related legislation and regulations, including the Infrastructure Investment and Jobs Act, signed into law in November 2021; the development of the Enhancement and Standardization of Climate-Related Disclosures, proposed by the SEC in March 2022; the IRA, signed into law in August 2022; and the EPA's proposed methane regulations for the oil and natural gas industry, but we cannot predict their impact on our business at this time. We have identified potential opportunities associated with the Infrastructure Investment and Jobs Act and the IRA and are evaluating how they may align with our strategy going forward. The energy-related provisions of the Infrastructure Investment and Jobs Act include new federal funding for power grid infrastructure and resiliency investments, new and existing energy efficiency and weatherization programs, electric vehicle infrastructure for public chargers and additional LIHEAP funding over the next five years. The IRA contains climate and energy provisions, including funding to decarbonize the electric sector.

In February 2021, the United States rejoined the Paris Agreement, an international treaty through which parties set nationally determined contributions to reduce GHG emissions, build resilience, and adapt to the impacts of climate change. Subsequently, the Biden Administration released a target for the United States to achieve a 50%-52% GHG reduction from 2005 levels by 2030, which supports the President's goals to create a carbon-free power sector by 2035 and net zero emissions economy no later than 2050. There are many pathways to reach these goals.

On June 30, 2022, the Supreme Court of the United States ruled for the petitioners in West Virginia v. EPA, which examined the authority of the EPA to regulate GHG emissions from the power sector. We will continue to evaluate this matter, but we remain committed to our previously stated carbon reduction goals.

We also continue to monitor the implementation of any final and proposed state policy. The Virginia Clean Economy Act was signed into law in 2020. While the Act does not establish any new mandates on Columbia of Virginia, certain natural gas customers may, over the long-term, reduce their use of natural gas to meet the 100% renewable electricity requirement. Columbia of Virginia will continue to monitor this matter, but we cannot predict its final impact on our business at this time. Separately, the Virginia Energy Innovation Act, enacted into law in April 2022, and effective July 1, 2022, allows natural gas utilities to supply alternative forms of gas that meet certain standards and reduce emissions intensity. The Act also provides that the costs of enhanced leak detection and repair may be added to a utility's plan to identify proposed eligible infrastructure replacement projects and related cost recovery mechanisms, known as the SAVE Plan. Furthermore, under the Act, utilities can recover eligible biogas supply infrastructure costs on an ongoing basis. The provisions of these laws may provide opportunities for Columbia of Virginia as it participates in the transition to a lower carbon future.

The Climate Solutions Now Act of 2022 requires Maryland to reduce GHG emissions by 60% by 2031 (from 2006 levels), and it requires the state to reach net zero emissions by 2045. The Maryland Department of the Environment is required to adopt a plan to achieve the 2031 goal by December 2023, and it is required to adopt a plan for the net zero goal by 2030. The Act also enacts a state policy to move to broader electrification of both existing buildings and new construction, and requires the Public Service Commission to complete a study assessing the capacity of gas and electric distribution systems to successfully serve customers under a transition to a highly electrified building sector. Columbia of Maryland will continue to monitor this matter, but we cannot predict its final impact on our business at this time.

NIPSCO, Columbia of Maryland, Columbia of Pennsylvania, Columbia of Virginia and Columbia of Kentucky each filed petitions to implement the Green Path Rider, which will be a voluntary rider that allows customers to opt in and offset either 50% or 100% of their natural gas related emissions. To reduce the emissions, the utilities will purchase RNG attributes and carbon offsets to match the usage for customers opting into the program. The program was approved by the IURC at NIPSCO in November 2022 with a January 2023 start date. After reaching settlement with other parties in September 2022, NIPSCO agreed to add a third tier to offset 25% of customer usage. Columbia of Maryland's filing was denied by the PUC in January 2023. The filings for Columbia of Pennsylvania, Columbia of Virginia and Columbia of Kentucky are still being evaluated. Additionally, NIPSCO has a voluntary Green Power Rider program in place that allows customers to designate a portion or all their monthly electric usage to come from power generated by renewable energy sources.

Net Zero Goal. In response to these transition risks and opportunities, on November 7, 2022, we announced a goal of net zero greenhouse gas emissions by 2040 covering both Scope 1 and Scope 2 emissions ("Net Zero Goal"). Our Net Zero Goal builds on greenhouse gas emission reductions achieved to-date and demonstrates that continued execution of our long-term business plan will drive further greenhouse gas emission reductions. We remain on track to achieve previously announced interim greenhouse gas emission reduction targets by reducing fugitive methane emissions from main and service lines by 50 percent from 2005 levels by 2025 and reducing Scope 1 greenhouse gas emissions from company-wide operations by 90 percent from 2005 levels by 2030. We plan to achieve our Net Zero Goal primarily through continuation and enhancement of existing programs, such as retiring and replacing coal-fired electric generation with low- or zero-emission electric generation, ongoing pipe replacement and modernization programs, and deployment of advanced leak-detection technologies. In addition, we plan to advance other low- or zero-emission energy resources and technologies, such as hydrogen, renewable natural gas, and/or deployment of carbon capture and utilization technologies, if and when these become technologically and economically feasible. Carbon offsets and renewable energy credits may also be used to support achievement of our Net Zero Goal. As of the end of 2021, we had reduced Scope 1 GHG emissions by approximately 58% from 2005 levels.

Our greenhouse gas emissions projections, including achieving a Net Zero Goal, are subject to various assumptions that involve risks and uncertainties. Achievement of our Net Zero Goal by 2040 will require supportive regulatory and legislative policies, favorable stakeholder environments and advancement of technologies that are not currently economical to deploy. Should such regulatory and legislative policies, stakeholder environments or technologies fail to materialize, our actual results or ability to achieve our Net Zero Goal, including by 2040, may differ materially.

As discussed in Management's Discussion within "Results and Discussion of Segment Operations - Electric Operations," NIPSCO continues to execute on an electric generation transition consistent with the preferred pathways identified in its 2018 and 2021 Integrated Resource Plans. Additionally, as discussed in Management's Discussion within "Liquidity and Capital Resources - Regulatory Capital Programs," our natural gas distribution companies are lowering methane emissions by replacing aging infrastructure, which also increases safety and reliability for customers and communities.

Human Capital

Human Capital Management Governance and Organizational Practices. The Compensation and Human Capital Committee of our Board of Directors (the "Board") is primarily responsible for assisting the Board in overseeing our human capital management practices. The Compensation and Human Capital Committee charter includes reviewing our human capital management function and programs, including related procedures, programs, policies and practices, and making recommendations to management with respect to equal employment opportunity and DE&I initiatives, employee engagement and corporate culture, and talent management.

In addition to overseeing our human capital management practices, in 2022 our Board was refreshed and is committed to ensuring that the Board is comprised of directors with diverse skills, expertise, experience and demographics, including racial and gender diversity. Women and people of color ("POC") each comprise 33% of our Board.

Human Capital Goals and Objectives. We have aligned our human capital goals to achieve overall company strategic and operational objectives by driving an enhanced talent strategy, elevating support for front-line leaders, fostering a culture of rigor and accountability and strengthening our human resources function. We aspire to be an employer of choice in the utility industry through accelerating and embedding DE&I throughout the enterprise and creating an enviable employee experience.

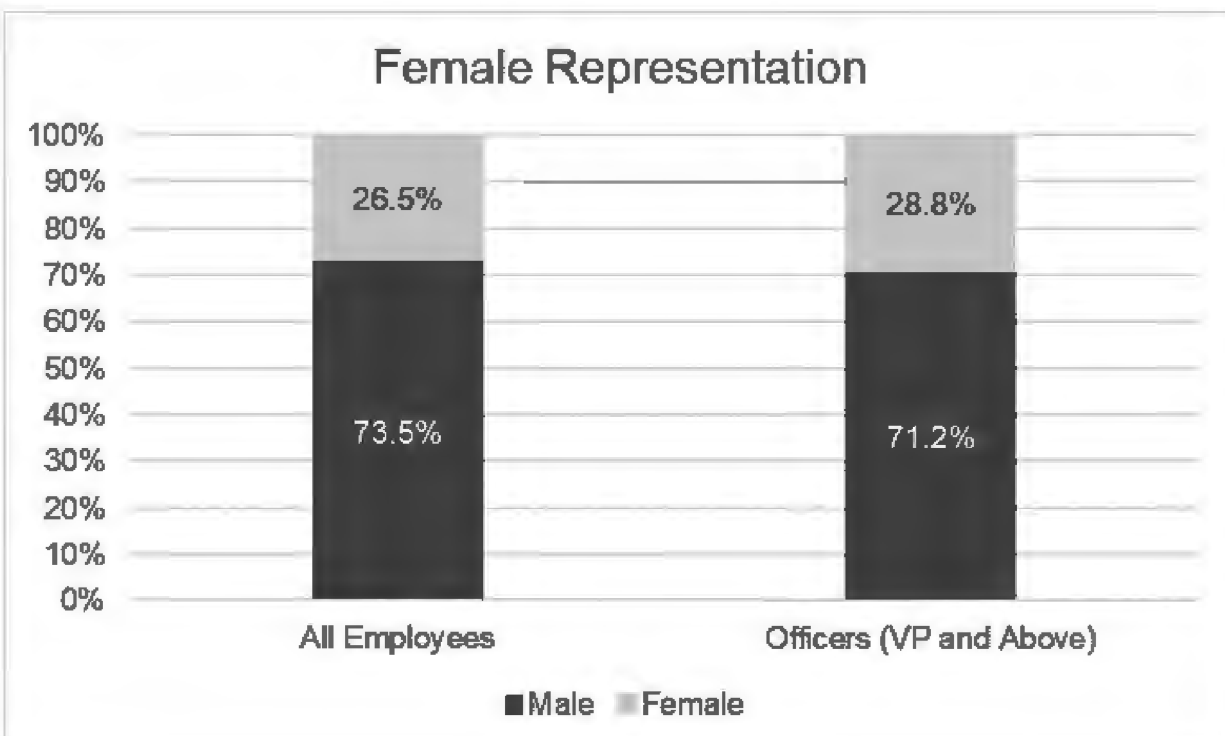
Workforce Composition. As of December 31, 2022, we had 7,117 full-time and 45 part-time active employees. Thirty-five percent of our employees were subject to collective bargaining agreements with various labor unions which expire between 2026 and 2027.

Diversity, Equity and Inclusion. We are committed to accelerating and embedding DE&I throughout the enterprise to reflect the communities and customers we serve. We have worked to develop diverse sourcing strategies to attract and increase our diverse representation. Our talent acquisition team hired 523 external candidates in 2022 across all business segments. Twenty-eight percent of external hires in 2022 were racially or ethnically diverse and 44% were female.

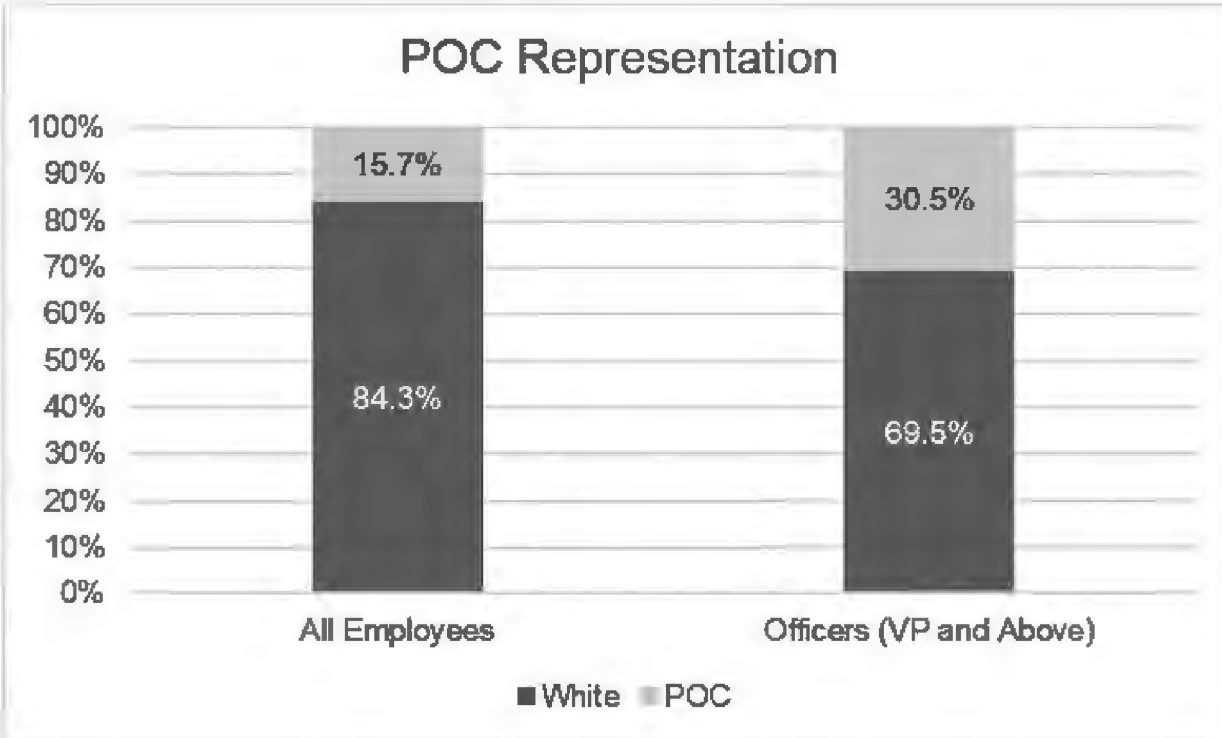
In addition, we have focused on our implementation and development of programs to drive higher retention and engagement of our employees. Through our efforts, we have been able to increase participation in our Targeted Development for Diverse Talent program in 2022. Participants in this program are either female or POC. POC make up 49% of the participant population for 2022. In addition, we have implemented over 50 DE&I programs with a strong emphasis on professional development and retention efforts within our seven Employee Resource Groups.

We plan to post our 2022 consolidated EEO-1 report data on our website by the end of the first quarter of 2023.

The following graph shows the percentage of total employees represented by gender overall and for our officers as of December 31, 2022:



The following graph shows the percentage of total employees and officers represented by race/ethnicity as of December 31, 2022:



Talent Attraction. To recruit and hire individuals with a variety of skills, talents, backgrounds and experiences, we value and cultivate relationships with the community and diverse outreach partners. We also target job fairs, including those focused on people of color, veterans and women candidates, and partner with local colleges and universities to identify and recruit qualified applicants in the communities we serve.

We are focused on our future of work and creating a more flexible, agile model for roles that can be performed in a more remote setting to attract talent across our footprint. In 2022, we introduced a hybrid-working model, which recognizes differing ways of working: onsite, hybrid and remote. As of December 31, 2022, 58% of our workforce is onsite, 35% are hybrid and 7% are remote. This new working model supports colleague connection, development and mentoring as well as broader team building.

Talent Development and Retention. We offer leadership development programs to enhance the behaviors and skills of our existing and future leaders. In 2022, we had participation from employees at all levels in our extensive technical and non-technical employee leadership development training programs.

We strive to provide promotion and advancement opportunities for employees. In 2022, for all leadership positions at the supervisor and above level posted externally, we filled 69% with internal employees. We develop and implement targeted development action plans to increase succession candidate readiness for leadership roles. Additionally, we monitor the risk and potential impact of talent loss and take action to increase retention of top talent. Retention in 2022 was over 91%. We calculate retention as the total number of separations divided by the average headcount for the annual period. These separations include involuntary separation (2%), resignation (5%), and retirement (2%).

Executive Succession Planning. We perform succession planning quarterly for officer level positions to ensure that we develop and sustain a strong bench of talent capable of performing at the highest levels. Talent is identified, and potential paths of development are discussed to ensure that employees have an opportunity to build their skills and are well-prepared for future roles. We maintain formal succession plans for our Chief Executive Officer ("CEO") and key executive officers. The succession plan for our CEO is reviewed by the Environmental, Social, Nominating and Governance Committee of the Board and the succession plans for executive officers (other than the CEO) and other critical roles are reviewed by the Compensation and Human Capital Committee annually or more frequently as needed.

Employee and Workplace Health and Safety. We have several programs to support employees, and their families' physical, mental, and financial well-being. These programs include a paid wellness day, telemedicine services, an Employee Assistance Program, Integrated Health Management navigation services, employee paid sick/disability leave, parental leave, and paid illness in family days. We also offer competitive medical, dental, vision, life and long-term disability programs, including employee health savings account company contributions.

We have a robust program to support employee, contractor and public safety, which is led by our Chief Safety Officer and is overseen by the Safety, Operations, Regulatory and Policy Committee of our Board. As we will outline in our annual safety report on our corporate website, we continue to invest in risk reduction activities and assets.

Culture and Engagement. Our culture is another important aspect of our ability to advance our strategic and operational objectives. In addition to our DE&I, recruiting, development and retention programs described above, we also invest in internal communications programs, including in-person and virtual learning and networking opportunities, as well as regular town hall communications with employees. We measure and monitor culture and employee engagement through a variety of channels including employee lifecycle, pulse, and census surveys.

To instill and reinforce our values and culture, we require our employees to participate in regular trainings on ethics and compliance topics each year, including raising concerns, treating others with respect, preventing discrimination in the workplace, anti-bribery and corruption, data protection, unconscious biases, harassment, conflicts of interest, and how to use the anonymous ethics and compliance hotline. All employees receive training on our Code of Business Conduct biannually or more frequently if there is a material change in content. Our business ethics program, including the employee training program, is reviewed annually by our executive leadership team and the Audit Committee of our Board.

Our Compensation and Human Capital Committee reviews reports from our Chief Human Resources Officer and Chief Diversity, Equity and Inclusion Officer on employee engagement and corporate culture. Our Board reviews results and action plans related to our enterprise-wide comprehensive employee engagement survey. Our executive leadership team, including our Chief Executive Officer, communicates directly and regularly with all employees on timely ethics topics through electronic messages, coffee chats, and all-employee town hall meetings. These communications emphasize the importance of our values and culture in the workplace.

Other Relevant Business Information

Our customer base is broadly diversified, with no single customer accounting for a significant portion of revenues.

For a listing of material subsidiaries of NiSource, refer to Exhibit 21.

We electronically file various reports with the SEC, including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to such reports, as well as our proxy statements for the Company's annual meetings of stockholders at *http://www.sec.gov*. Additionally, we make all SEC filings available without charge to the public on our web site at *http://www.nisource.com*. The information contained on our website is not included in, nor incorporated by reference into, this Annual Report on Form 10-K.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

NiSource Inc.

The following is a list of our Executive Officers, including their names, ages, offices held and other recent business experience.

Name	Age	Office(s) Held in Past 5 Years
Lloyd M. Yates	62	President and Chief Executive Officer
		Executive Vice President, Customer and Delivery Operations, and President, Carolinas Region, of Duke Energy Corporation from 2014 to 2019.
Donald E. Brown	51	Executive Vice President and Chief Financial Officer
		Executive Vice President of NiSource since May 2015.
		Chief Financial Officer of NiSource since July 2015.
		President, NiSource Corporate Services since June 2020.
Melody Birmingham	51	Executive Vice President, Chief Innovation Officer
		Senior Vice President and Chief Administrator Officer of Duke Energy Corporation from May 2021 to June 2022.
		Senior Vice President, Supply Chain and Chief Procurement Officer of Duke Energy Corporation from November 2018 to April 2021.
		President of Duke Energy Corporation from June 2015 to November 2018
William Jefferson, Jr	61	Executive Vice President, Operations and Chief Safety Officer
		Station Director and Vice President at STPNOC, Wadsworth, Texas, from 2016 to May 2022.
Shawn Anderson	41	Senior Vice President,Strategy and Chief Risk Officer
		Vice President, Strategy of NiSource from January 2019 to May 2020.
		Vice President of NiSource from May 2018 to December 2018.
		Treasurer and Chief Risk Officer of NiSource from June 2016 to December 2018.
Kimberly S. Cuccia	39	Senior Vice President, General Counsel and Corporate Secretary
		Vice President General Counsel, Interim Corporate Secretary of NiSource from January 2022 to March 2022.
		Vice President and Deputy General Counsel, Regulatory, of NiSource Corporate Services Company, from January 2021 to December 2021.
		Vice President and General Counsel, Columbia Gas of Massachusetts, NiSource Corporate Services Company, from October 2019 to December 2020.
		Vice President and General Counsel, Massachusetts Restoration, NiSource Corporate Services Company, from October 2018 to October 2019.
		Chief Counsel, Columbia Gas Companies from June 2015 to September 2018.
Melanie B. Berman	52	Senior Vice President and Chief Human Resources Officer
		Executive Vice President and Chief Human Resources Officer of The Michaels Companies, Inc. from 2020 to 2021.
		Vice President, Human Resources of Anthem, Inc. from January 2018 to 2019.

NISOURCE INC.

Our operations and financial results are subject to various risks and uncertainties, including those described below, that could adversely affect our business, financial condition, results of operations, cash flows, and the market price of our common stock.

OPERATIONAL RISKS

We may not be able to complete the sale of a minority interest in NIPSCO on the expected timeline or at all.

On November 7, 2022, we announced our intention to sell a minority interest in NIPSCO (the "NIPSCO Minority Interest Sale"). We intend to evaluate various alternatives to determine the optimal transaction structure to maximize stakeholder value as a result of the NIPSCO Minority Interest Sale. A successful sale will be dependent on factors such as regulatory approval(s) and negotiations with one or more counterparties. There can be no assurances that we will be able to successfully complete the NIPSCO Minority Interest Sale on the anticipated timeline or at all. Furthermore, there can be no assurances that the NIPSCO Minority Interest Sale will lead to the anticipated benefits to stockholders.

We may not be able to execute our business plan or growth strategy, including the NIPSCO Minority Interest Sale and utility infrastructure investments.

Business or regulatory conditions may result in our inability to execute our business plan or growth strategy, including the NIPSCO Minority Interest Sale and identified, planned and other utility infrastructure investments, which includes investments related to natural gas pipeline modernization and our renewable energy projects, and the build-transfer execution goals within our business plan.

Our Enterprise Transformation Roadmap initiatives are designed to identify long-term sustainable capability enhancements, cost optimization improvements, technology investments and work process optimization, has increased the volume and pace of change and may not be effective as it continues. Our customer and regulatory initiatives may not achieve planned results. Utility infrastructure investments may not materialize, may cease to be achievable or economically viable and may not be successfully completed. Natural gas may cease to be viewed as an economically and environmentally attractive fuel. Certain environmental activist groups, investors and governmental entities continue to oppose natural gas delivery and infrastructure investments because of perceived environmental impacts associated with the natural gas supply chain and end use. Energy conservation, energy efficiency, distributed generation, energy storage, policies favoring electric heat over gas heat and other factors may reduce demand for natural gas and electricity. In addition, we consider acquisitions or dispositions of assets or businesses, JVs, including in connection with the NIPSCO Minority Interest Sale, and mergers from time to time as we execute on our business plan and growth strategy. Any of these circumstances could adversely affect our results of operations and growth prospects. Even if our business plan and growth strategy are executed, there is still risk of, among other things, human error in maintenance, installation or operations, shortages or delays in obtaining equipment, including as a result of transportation delays and availability, labor availability and performance below expected levels (in addition to the other risks discussed in this section). We are currently experiencing, and expect to continue to experience, supply chain challenges, including labor availability issues, impacting our ability to obtain materials for our gas and electric projects. Risks to our capital projects, including risks related to supply chain challenges and labor availability, are described in a separate risk factor below.

Our gas distribution and transmission activities, as well as generation, transmission and distribution of electricity, involve a variety of inherent hazards and operating risks, including potential public safety risks.

Our gas distribution and transmission activities, as well as generation, transmission and distribution of electricity, involve a variety of inherent hazards and operating risks, including, but not limited to, gas leaks and over-pressurization, downed power lines, stray electrical voltage, excavation or vehicular damage to our infrastructure, outages, environmental spills, mechanical problems and other incidents, which could cause substantial financial losses, as demonstrated in part by the Greater Lawrence Incident. We also have distribution propane assets that involve similar risks. In addition, these hazards and risks have resulted and may result in the future in serious injury or loss of life to employees and/or the general public, significant damage to property, environmental pollution, impairment of our operations, adverse regulatory rulings and reputational harm, which in turn could lead to substantial losses for NiSource and its stockholders. The location of pipeline facilities, including regulator stations, liquefied natural gas and underground storage, or generation, transmission, substation and distribution facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from such incidents. As with the Greater Lawrence Incident, certain incidents have subjected and may in the future subject us to both civil and criminal litigation or administrative or other legal proceedings from time to time, which could result in substantial monetary judgments, fines, or penalties against us, be resolved on unfavorable terms, and require us to incur significant operational expenses. The occurrence of incidents has in certain instances adversely affected and could in the future adversely affect our reputation, cash flows, financial position and/or results of operations. We maintain insurance against some, but not all, of these risks and losses.

We may conduct certain operations, including in connection with the NIPSCO Minority Interest Sale, through a JV arrangement involving third-party investors that may result in delays, litigation or operational impasses.

We may enter into JV arrangements involving third-party investors, including in connection with the NIPSCO Minority Interest Sale. As part of a JV arrangement, third-party investors may hold certain protective rights that may impact our ability to make certain decisions. Any such third-party investors may have interests and objectives which may differ from ours and, accordingly, disputes may arise that may result in delays, litigation or operational impasses.

Failure to adapt to advances in technology and manage the related costs could make us less competitive and negatively impact our results of operations and financial condition.

A key element of our electric business model includes generating power at central station power plants to achieve economies of scale and produce power at a competitive cost. We continue to transition our generation portfolio in order to implement new and diverse technologies including renewable energy, distributed generation, energy storage, and energy efficiency designed to reduce regulated emissions. Advances in technology and potential competition supported by changes in laws or regulations could reduce the cost of electric generation and provide retail alternatives causing power sales to decline and the value of our generating facilities to decline.

Our natural gas business model depends on widespread utilization of natural gas for space heating as a core driver of revenues. Alternative energy sources, new technologies or alternatives to natural gas space heating, including cold climate heat pumps and/or efficiency of other products, could reduce demand and increase customer attrition, which could impact our ability to recover on our investments in our gas distribution assets.

Our future success will depend, in part, on our ability to anticipate and successfully adapt to technological changes, to offer services that meet customer demands and evolving industry standards, including environmental impacts associated with our products and services, and to recover all, or a significant portion of, remaining investments in retired assets. A failure by us to effectively adapt to changes in technology and manage the related costs could harm the ability of our products and services to remain competitive in the marketplace and could have a material adverse impact on our results of operations and financial condition.

Aging infrastructure may lead to disruptions in operations and increased capital expenditures and maintenance costs, all of which could negatively impact our financial results.

We have risks associated with aging electric and gas infrastructure. These risks can be driven by threats such as, but not limited to, electrical faults, mechanical failure, internal corrosion, external corrosion, ground movement and stress corrosion and/or cracking. The age of these assets may result in a need for replacement, a higher level of maintenance costs or unscheduled outages, despite efforts by us to properly maintain or upgrade these assets through inspection, scheduled maintenance and capital investment. In addition, the nature of the information available on aging infrastructure assets, which in some cases is incomplete, may make the operation of the infrastructure, inspections, maintenance, upgrading and replacement of the assets particularly challenging. Missing or incorrect infrastructure data may lead to (1) difficulty properly locating facilities, which can result in excavator damage and operational or emergency response issues, and (2) configuration and control risks associated with the modification of system operating pressures in connection with turning off or turning on service to customers, which can result in unintended outages or operating pressures. Also, additional maintenance and inspections are required in some instances to improve infrastructure information and records and address emerging regulatory or risk management requirements, resulting in increased costs.

Supply chain issues related to shortages of materials and transportation logistics may lead to delays in the maintenance and replacement of aging infrastructure, which could increase the probability and/or impact of a public safety incident. We lack diversity in suppliers of some gas materials. While we have implemented contractual protections with suppliers and stockpile some materials in inventory for such supply risks, we may not be effective in ensuring that we can obtain adequate emergency supply on a timely basis in each state, that no compromises are being made on quality and that we have alternate suppliers available. The failure to operate our assets as desired could result in interruption of electric service, major component failure at generating facilities and electric substations, gas leaks and other incidents, and an inability to meet firm service and compliance obligations, which could adversely impact revenues, and could also result in increased capital expenditures and maintenance costs, which, if not fully recovered from customers, could negatively impact our financial results.

We may be unable to obtain insurance on acceptable terms or at all, and the insurance coverage we do obtain may not provide protection against all significant losses.

Our ability to obtain insurance, as well as the cost and coverage of such insurance, are affected by developments affecting our business; international, national, state, or local events; and the financial condition and underwriting considerations of insurers. For example, some insurers are moving away from underwriting certain carbon-intensive energy-related businesses such as those in the coal industry or those exposed to specific perils such as wildfires as well as gas explosion events or other infrastructure-related or natural catastrophe risks. The utility insurance market continues to be impacted by a prevalence of severe losses, and despite significant annual increases in rates over the past few years, markets are experiencing unacceptable loss ratios. Certain perils, such as cyber, are now being excluded from some master policies for property and casualty insurance, requiring procurement of additional policies to be obtained to maintain consistent coverage at an additional cost. Capacity limits insurers are willing to issue have decreased, requiring participation from more insurers to provide adequate coverage. Insurance coverage may not continue to be available at limits, rates or terms acceptable to us. In addition, our insurance is not sufficient or effective under all circumstances and against all hazards or liabilities to which we are subject. Certain types of damages, expenses or claimed costs, such as fines and penalties, have been and in the future may be excluded under the policies. In addition, insurers providing insurance to us may raise defenses to coverage under the terms and conditions of the respective insurance policies that could result in a denial of coverage or limit the amount of insurance proceeds available to us. Any losses for which we are not fully insured or that are not covered by insurance at all could materially adversely affect our results of operations, cash flows and financial position.

Aspects of the implementation of our electric generation strategy, including the retirement of our coal generation units, may be delayed and may not achieve intended results.

As discussed in “Results and Discussion of Segment Operations - Electric Operations,” in Management’s Discussion and Analysis of Financial Condition and Results of Operations, our 2018 Integrated Resource Plan (“2018 Plan”) outlines the path to retire the remaining two coal units at R.M. Schahfer by the end of 2025 and the remaining coal-fired generation by the end of 2028, to be replaced by lower-cost, reliable and cleaner options. Our 2021 Integrated Resource Plan (“2021 Plan”) validated the activities underway pursuant to our 2018 Plan and calls for the retirement of the Michigan City Generating Station, replacement of existing vintage gas peaking units at the R.M. Schahfer Generating Station and upgrades to the transmission system to enhance our electric generation transition. Recent developments, including macro supply chain issues and U.S. federal policy actions, have created significant uncertainty around the availability of key input material necessary to develop and place our renewable energy projects in service. In the U.S., solar industry supply chain issues include the pending U.S. Department of Commerce investigation on Antidumping and Countervailing Duties Anti Circumvention Petition filed by a domestic solar manufacturer (the “DOC Investigation”), the Uyghur Forced Labor Protection Act, Section 201 Tariffs and persistent general global supply chain and labor availability issues. The most prominent effect of these issues is the significant curtailment of imported solar panels and other key components required to complete utility scale solar projects in the U.S. Any available solar panels may not meet the cost and efficiency standards of our currently approved projects and the incremental cost may not be recoverable through customer rates. As a result of the challenges in obtaining solar panels, many solar projects in the U.S. have been delayed or canceled. As we are in the midst of a transition to an electric generation portfolio with more renewable resources, including solar, our projects are subject to the effects of these issues.

Our expectation has been that solar energy sources would be one of the primary ways in which we will meet our electric generation capacity and reliability obligations to the MISO market and reliably serve our customers when we retire our coal generation capacity. The high level of uncertainty surrounding the completion of our solar renewable energy projects creates significant risks for us to reliably meet our capacity and energy obligations to MISO and to provide reliable and affordable energy to our customers. Any additional delays to the completion dates of our ten planned and approved solar projects are expected to impact our capacity position and our ability to meet our resource adequacy obligations to MISO. Delays to the completion dates of our projects could also include delays in the financial return of certain investments and impact the overall timing of our electric generation transition.

As noted above, we expect our electric generation strategy to require additional investment to meet our MISO obligations and may require significant future capital expenditures, operating costs and charges to earnings that may negatively impact our financial position, financial results and cash flows. An inability to secure and deliver on renewable projects is negatively impacting our generation transition timeline and may negatively impact our achievement of decarbonization goals and reputation.

Our capital projects and programs subject us to construction risks and natural gas costs and supply risks, and are subject to regulatory oversight, including requirements for permits, approvals and certificates from various governmental agencies.

Our business requires substantial capital expenditures for investments in, among other things, capital improvements to our electric generating facilities, electric and natural gas distribution infrastructure, natural gas storage and other projects, including projects for environmental compliance. As we undertake these projects and programs, we may be unable to complete them on schedule or at the anticipated costs due in part to shortages in materials as described more fully below. Additionally, we may construct or purchase some of these projects and programs to capture anticipated future growth, which may not materialize, and may cause the construction to occur over an extended period of time.

Our existing and planned capital projects require numerous permits, approvals and certificates from federal, state, and local governmental agencies. If there is a delay in obtaining any required regulatory approvals or if we fail to obtain or maintain any required approvals or to comply with any applicable laws or regulations, we may not be able to construct or operate our facilities, we may be forced to incur additional costs or we may be unable to recover any or all amounts invested in a project. We also may not receive the anticipated increases in revenue and cash flows resulting from such projects and programs until after their completion. Other construction risks include changes in the availability and costs of materials, equipment, commodities or labor (including changes to tariffs on materials), delays caused by construction incidents or injuries, work stoppages, shortages in qualified labor, poor initial cost estimates, unforeseen engineering issues, the ability to obtain necessary rights-of-way, easements and transmissions connections and general contractors and subcontractors not performing as required under their contracts.

We are monitoring risks related to increasing order and delivery lead times for construction and other materials, increasing risk associated with the unavailability of materials due to global shortages in raw materials and issues with transportation logistics, and risk of decreased construction labor productivity in the event of disruptions in the availability of materials critical to our gas and electric operations. Our efforts to enhance our resiliency to supply chain shortages may not be effective. We are also seeing increasing prices associated with certain materials, equipment and products, which impacts our ability to complete major capital projects at the cost that was planned and approved. To the extent that delays occur or costs increase, customer affordability as well as our business operations, results of operations, cash flows and financial condition could be materially adversely affected. In addition, to the extent that delays occur on projects that target system integrity, the risk of an operational incident could increase. For more information on global availability of materials for our renewable projects, see " - Results and Discussion of Segment Operations - Electric Operations - Electric Supply and Generation Transition." To the extent that delays occur, costs become unrecoverable or recovery is delayed, or we otherwise become unable to effectively manage and complete our capital projects, our results of operations, cash flows, and financial condition may be adversely affected.

A significant portion of the gas and electricity we sell is used by residential and commercial customers for heating and air conditioning. Accordingly, fluctuations in weather, gas and electricity commodity costs, inflation and economic conditions impact demand of our customers and our operating results.

Energy sales are sensitive to variations in weather. Forecasts of energy sales are based on "normal" weather, which represents a long-term historical average. Significant variations from normal weather resulting from climate change or other factors could have, and have had, a material impact on energy sales. Additionally, residential usage, and to some degree commercial usage, is sensitive to fluctuations in commodity costs for gas and electricity, whereby usage declines with increased costs, thus affecting our financial results. Commodity prices have been and may continue to be volatile. Rising gas costs could heighten regulator and stakeholder sensitivity relative to the impact of base rate increases on customer affordability. Lastly, residential and commercial customers' usage is sensitive to economic conditions and factors such as recession, inflation, unemployment, consumption and consumer confidence. Therefore, prevailing economic conditions affecting the demand of our customers may in turn affect our financial results.

Fluctuations in the price of energy commodities or their related transportation costs or an inability to obtain an adequate, reliable and cost-effective fuel supply to meet customer demands may have a negative impact on our financial results.

Our current electric generating fleet is dependent on coal and natural gas for fuel, and our gas distribution operations purchase and resell a portion of the natural gas we deliver to our customers. These energy commodities are subject to price fluctuations and fluctuations in associated transportation costs. We use physical hedging through the use of storage assets and use financial products in certain jurisdictions in order to offset fluctuations in commodity supply prices. We rely on regulatory recovery mechanisms in the various jurisdictions in order to fully recover the commodity costs incurred in selling energy to our customers. However, while we have historically been successful in the recovery of costs related to such commodity prices, there can be no assurance that such costs will be fully recovered through rates in a timely manner.

In addition, we depend on electric transmission lines, natural gas pipelines, and other transportation facilities owned and operated by third parties to deliver the electricity and natural gas we sell to wholesale markets, supply natural gas to our gas storage and electric generation facilities, and provide retail energy services to our customers. If transportation is disrupted, if capacity is inadequate or if supply is interrupted due to issues at the wellhead, we may be unable to sell and deliver our gas and electric services to some or all of our customers. As a result, we may be required to procure additional or alternative electricity and/or natural gas supplies at then-current market rates, which, if recovery of related costs is disallowed, could have a material adverse effect on our businesses, financial condition, cash flows, results of operations and/or prospects.

Failure to attract and retain an appropriately qualified workforce, and maintain good labor relations, could harm our results of operations.

We operate in an industry that requires many of our employees and contractors to possess unique technical skill sets. An aging workforce without appropriate replacements, the mismatch of skill sets to future needs, the unavailability of talent for internal positions and the unavailability of contract resources may lead to operating challenges or increased costs. These operating challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. For example, certain skills, such as those related to construction, maintenance and repair of transmission and distribution systems, are in high demand and have a limited supply. Current and prospective employees may determine that they do not wish to work for us due to market, economic, employment and other conditions, including those related to organizational changes as described in the risk factor below.

We face increased competition for talent in the current environment of sustained labor shortage and increased turnover rates. Incidents of any pandemic in our workforce could increase the risk of worker illness and availability. These or other employee workforce factors could negatively impact our business, financial condition or results of operations.

A significant portion of our workforce is subject to collective bargaining agreements. Our collective bargaining agreements are generally negotiated on an operating company basis with some companies having multiple bargaining agreements, which may span different geographies. Any failure to reach an agreement on new labor contracts or to renegotiate these labor contracts might result in strikes, boycotts or other labor disruptions. Our workforce continuity plans may not be effective in avoiding work stoppages that may result from labor negotiations or mass resignations. Labor disruptions, strikes or significant negotiated wage and benefit increases, whether due to union activities, employee turnover or otherwise, could have a material adverse effect on our businesses, results of operations and/or cash flows.

Our strategic plan includes enhanced technology and transmission and distribution investments and a reduction in reliance on coal-fired generation. As part of our strategic plan, we will need to attract and retain personnel that are qualified to implement our strategy and may need to retrain or re-skill certain employees to support our long-term objectives.

Failure to hire and retain qualified employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, may adversely affect our ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce and maintain satisfactory collective bargaining agreements, safety, service reliability, customer satisfaction and our results of operations could be adversely affected.

If we cannot effectively manage new initiatives and organizational changes, we will be unable to address the opportunities and challenges presented by our strategy and the business and regulatory environment.

In order to execute on our sustainable growth strategy and enhance our culture of ongoing continuous improvement, we must effectively manage the complexity and frequency of new initiatives and organizational changes. The organizational changes from our transformation initiatives have put short-term pressure on employees due to the volume and pace of change and, in some cases, loss of personnel. Front-line workers are being impacted by the variety of process and technology changes that are currently in progress.

If we are unable to make decisions quickly, assess our opportunities and risks, and successfully implement new governance, managerial and organizational processes as needed to execute our strategy in this increasingly dynamic and competitive business and regulatory environment, our financial condition, results of operations and relationships with our business partners, regulators, customers, employees and stockholders may be negatively impacted.

Actions of activist stockholders could negatively affect our business and stock price and cause us to incur significant expenses.

We may be subject to actions or proposals from activist stockholders or others that may not be aligned with our long-term strategy or the interests of our other stockholders. We have had communications with an activist stockholder. Our response to suggested actions, proposals, director nominations and contests for the election of directors by activist stockholders could disrupt our business and operations, divert the attention of our board of directors, management and employees and be costly and time-consuming. Potential actions by activist stockholders or others may interfere with our ability to execute our strategic plans; create perceived uncertainties as to the future direction of our business or strategy; cause uncertainty with our regulators; make it more difficult to attract and retain qualified personnel; and adversely affect our relationships with our existing and potential business partners. Any of the foregoing could adversely affect our business, financial condition and results of operations. Also, we may be required to incur significant fees and other expenses related to responding to stockholder activism, including for third-party advisors. Moreover, our stock price could be subject to significant fluctuation or otherwise be adversely affected by the events, risks and uncertainties of any stockholder activism.

We outsource certain business functions to third-party suppliers and service providers, and substandard performance by those third parties could harm our business, reputation and results of operations.

Utilities rely on extensive networks of business partners and suppliers to support critical enterprise capabilities across their organizations. Like other companies in the utilities industry, we are seeing slowing deliveries from suppliers and in some cases materials and labor shortages for capital projects. We outsource certain services to third parties in areas including construction services, information technology, materials, fleet, environmental, operational services, corporate and other areas. In addition to delays and unavailability at times, outsourcing of services to third parties could expose us to inferior service quality or substandard deliverables, which may result in non-compliance (including with applicable legal requirements and industry standards), interruption of service or accidents or reputational harm, which could negatively impact our results of operations. We do not have full visibility into our supply chain, which may impact our ability to serve customers in a safe, reliable and cost-effective manner. These risks include the risk of operational failure, reputation damage, disruption due to new supply chain disruptions, exposure to significant commercial losses and fines and poorly positioned and distressed suppliers. If we continue to see delayed deliveries and shortages or if any other difficulties in the operations of these third-party suppliers and service providers, including their systems, were to occur, they could adversely affect our results of operations, or adversely affect our ability to work with regulators, unions, customers or employees.

A cyber-attack on any of our or certain third-party technology systems upon which we rely may adversely affect our ability to operate and could lead to a loss or misuse of confidential and proprietary information or potential liability.

We are reliant on technology to run our business, which is dependent upon financial and operational technology systems to process critical information necessary to conduct various elements of our business, including the generation, transmission and distribution of electricity; operation of our gas pipeline facilities; and the recording and reporting of commercial and financial transactions to regulators, investors and other stakeholders. In addition to general information and cyber risks that all large corporations face (e.g., ransomware, malware, unauthorized access attempts, phishing attacks, malicious intent by insiders, third-party software vulnerabilities and inadvertent disclosure of sensitive information), the utility industry faces evolving and increasingly complex cybersecurity risks associated with protecting sensitive and confidential customer and employee information, electric grid infrastructure, and natural gas infrastructure. Deployment of new business technologies, along with maintaining legacy technology, represents a large-scale opportunity for attacks on our information systems and confidential customer and employee information, as well as on the integrity of the energy grid and the natural gas infrastructure. Additionally, the conflict between Russia and Ukraine, as well as increased surveillance activity from China, has increased the likelihood of a cyber-attack on critical infrastructure systems.

Increasing large-scale corporate attacks in conjunction with more sophisticated threats continue to challenge power and utility companies. Any failure of our technology systems, or those of our customers, suppliers or others with whom we do business, could materially disrupt our ability to operate our business and could result in a financial loss and possibly do harm to our reputation.

Additionally, our information systems experience ongoing, often sophisticated, cyber-attacks by a variety of sources, including foreign sources, with the apparent aim to breach our cyber-defenses. While we have implemented and maintain a cybersecurity program designed to protect our information technology, operational technology, and data systems from such attacks, our cybersecurity program does not prevent all breaches or cyberattack incidents. We have experienced an increase in the number of attempts by external parties to access our networks or our company data without authorization. We have experienced, and expect to continue to experience, cyber intrusions and attacks to our information systems and our operational technology. To our knowledge, none of these intrusions or attacks have resulted in a material cybersecurity intrusion or data breach. The risk of a disruption or breach of our operational technology, or the compromise of the data processed in connection with our operations, through cybersecurity breach or ransomware attack has increased as attempted attacks have advanced in sophistication and number around the world. Technological complexities combined with advanced cyber-attack techniques, lack of cyber hygiene and human error can result in a cybersecurity incident, such as a ransomware attack. Supplier non-compliance with cyber controls can also result in a cybersecurity incident. Attacks can occur at any point in the supply chain or with any suppliers. In addition, unmanned aircraft systems (UAS) or drones are used for various commercial and recreational purposes across the country. The Cybersecurity & Infrastructure Security Agency (CISA) released alerts pertaining to UASs being used for malicious activities and the cybersecurity risk is continuing to increase.

In addition, we collect and retain personally identifiable information of our customers, stockholders and employees. Customers, stockholders and employees expect that we will adequately protect their personal information. The regulatory environment surrounding information security and privacy is increasingly demanding.

Although we attempt to maintain adequate defenses to these attacks and work through industry groups and trade associations to identify common threats and assess our countermeasures, a security breach of our information systems and/or operational technology, or a security breach of the information systems of our customers, suppliers or others with whom we do business, could (i) adversely impact our ability to safely and reliably deliver electricity and natural gas to our customers through our generation, transmission and distribution systems and potentially negatively impact our compliance with certain mandatory reliability and gas flow standards, (ii) subject us to reputational and other harm or liabilities associated with theft or inappropriate release of certain types of information such as system operating information or information, personal or otherwise, relating to our customers or employees, (iii) impact our ability to manage our businesses, and/or (iv) subject us to legal and regulatory proceedings and claims from third parties, in addition to remediation costs, any of which, in turn, could have a material adverse effect on our businesses, cash flows, financial condition, results of operations and/or prospects. Although we do maintain cyber insurance, it is possible that such insurance will not adequately cover any losses or liabilities we may incur as a result of a cybersecurity incident.

Compliance with and changes in cybersecurity requirements have a cost and operational impact on our business, and failure to comply with such laws and regulations could adversely impact our reputation, results of operations, financial condition and/or cash flows.

As cyber-attacks are becoming more sophisticated, U.S. government warnings have indicated that critical infrastructure assets, including pipelines and electric infrastructure, may be specifically targeted by certain groups. In 2021, the Transportation Security Administration ("TSA") announced two new security directives in response to a ransomware attack on the Colonial Pipeline that occurred earlier in the year. These directives require critical pipeline owners to comply with mandatory reporting measures, designate a cybersecurity coordinator, provide vulnerability assessments, and ensure compliance with certain cybersecurity requirements. Such directives or other requirements may require expenditure of significant additional resources to respond to cyberattacks, to continue to modify or enhance protective measures, or to assess, investigate and remediate any critical infrastructure security vulnerabilities. Additionally, on November 30, 2022, the TSA issued an advance notice of proposed rulemaking (ANPRM) seeking public comment on more comprehensive, formal cybersecurity regulations for the pipeline industry. Any failure to comply with such government regulations or failure in our cybersecurity protective measures may result in enforcement actions that may have a material adverse effect on our business, results of operations and financial condition. In addition, there is no certainty that costs incurred related to securing against threats will be recovered through rates.

The impacts of natural disasters, acts of terrorism, acts of war, civil unrest, cyber-attacks, accidents, public health emergencies or other catastrophic events may disrupt operations and reduce the ability to service customers.

A disruption or failure of natural gas distribution systems, or within electric generation, transmission or distribution systems, in the event of a major hurricane, tornado, or other major weather event, or terrorist attack, acts of war, including the political and economic disruption and uncertainty related to Russia's military invasion of Ukraine, civil unrest, cyber-attack (as further detailed above), accident, public health emergency, pandemic, or other catastrophic event could cause delays in completing sales, providing services, or performing other critical functions. We have experienced disruptions in the past from hurricanes and tornadoes and other events of this nature. Also, companies in our industry face a heightened risk of exposure to and have experienced acts of terrorism and vandalism. Our electric and gas physical infrastructure may be targets of physical security threats or terrorist activities that could disrupt our operations. We have increased security given the current environment and may be required by regulators or by the future threat environment to make investments in security that we cannot currently predict. In addition, the supply chain constraints that we are experiencing could impact timely restoration of services. The occurrence of such events could adversely affect our financial position and results of operations. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses.

We are exposed to significant reputational risks, which make us vulnerable to a loss of cost recovery, increased litigation and negative public perception.

As a utility company, we are subject to adverse publicity focused on the reliability of our services, the speed with which we are able to respond effectively to electric outages, natural gas leaks or events and related accidents and similar interruptions caused by storm damage, physical or cyber security incidents, or other unanticipated events, as well as our own or third parties' actions or failure to act. We are subject to prevailing labor markets and potential high attrition, which may impact the speed of our customer service response. We are also facing supply chain challenges, the impacts of which may adversely impact our reputation in several areas as described elsewhere in these risk factors. We are also subject to adverse publicity related to actual or perceived environmental impacts. If customers, legislators or regulators have or develop a negative opinion of us, this could result in less favorable legislative and regulatory outcomes or increased regulatory oversight, increased litigation and negative public perception. The adverse publicity and investigations we experienced as a result of the Greater Lawrence Incident may have an ongoing negative impact on the public's perception of us. It is difficult to predict the ultimate impact of this adverse publicity. The foregoing may have continuing adverse effects on our business, results of operations, cash flow and financial condition.

The physical impacts of climate change and the transition to a lower carbon future are impacting our business and could materially adversely affect our results of operations.

Climate change is exacerbating risks to our physical infrastructure by increasing the frequency of extreme weather, including heat stresses to power lines, cold temperature stress to our electric and gas systems, and storms and floods that damage infrastructure. In addition, climate change is likely to cause lake and river level changes that affect the manner in which services are currently provided and droughts or other limits on water used to supply services, and other extreme weather conditions. We have adapted and will continue to evolve our infrastructure and operations to meet current and future needs of our stakeholders. With higher frequency of these and other possible extreme weather events it may become more costly for us to safely and reliably deliver certain products and services to our customers. Some of these costs may not be recovered. To the extent that we are unable to recover those costs, or if higher rates arising from recovery of such costs result in reduced demand for services, our future financial results may be adversely impacted. Further, as the intensity and frequency of significant weather events increases, insurers may reprice or remove themselves from insuring risks for which the company has historically maintained insurance, resulting in increased cost or risk to us.

Our strategy may be impacted by policy and legal, technology, market and reputational risks and opportunities that are associated with the transition to a lower-carbon economy, as disclosed in other risk factors in this section. As a result of increased awareness regarding climate change, coupled with adverse economic conditions, availability of alternative energy sources, including private solar, microturbines, fuel cells, energy-efficient buildings and energy storage devices, and new regulations restricting emissions, including potential regulations of methane emissions, some consumers and companies may use less energy, meet their own energy needs through alternative energy sources or avoid expansions of their facilities, including natural gas facilities, which may result in less demand for our services. As these technologies become a more cost-competitive option over time, whether through cost effectiveness or government incentives and subsidies, certain customers may choose to meet their own energy needs and subsequently decrease usage of our systems and services, which may result in, among other things, our generating facilities becoming less competitive and economical. Further, evolving investor sentiment related to the use of fossil fuels and initiatives to restrict continued production of fossil fuels could result in a significant impact on our electric generation and natural gas businesses in the future.

Some of our baseload generation is dependent on natural gas and coal, and we pass through the costs for these energy sources to our customers. In addition, in our gas distribution business, we procure natural gas on behalf of certain customers, and we pass through the actual cost of the gas consumed. Diminished investor interest in funding fossil fuel development could reduce the amount of exploration and production of natural gas or coal, or investment in gas transmission pipelines. Reduced production and transportation of natural gas could, in the long-term, lead to supply shortages leading to baseload generation outages. Given that we pass through commodity costs to customers, this could also create the potential for regulatory questions resulting from increased customer costs. We are unable to forecast the future of commodity markets, but reduced fossil fuel investment, due to evolving investor sentiment, could lead to higher commodity prices and shortages impacting our generation and our reputation with regulators. Conversely, demand for our services may increase as a result of customer changes in response to climate change. For example, as the utilization of electric vehicles increases, demand for electricity may increase, resulting in increased usage of our systems and services.

Any negative views with respect to our environmental practices or our ability to meet the challenges posed by climate change from regulators, customers, investors or legislators could harm our reputation and adversely affect the perceived value of our products and services. Changes in policy to combat climate change, and technology advancement, each of which can also accelerate the implications of a transition to a lower carbon economy, may materially adversely impact our business, financial position, results of operations, and cash flows. For example, in February 2023, the Maryland Office of People's Counsel filed a petition with the Maryland Public Service Commission seeking an investigation regarding planning, practices, and future operations of natural gas suppliers in the state.

We are subject to operational and financial risks and liabilities associated with the implementation and efforts to achieve our carbon emission reduction goals.

On November 7, 2022, we announced our goal of reaching net zero Scope 1 and 2 greenhouse gas emissions by 2040 (the "Net Zero Goal"). Achieving the Net Zero Goal will require supportive regulatory and legislative policies, favorable stakeholder environments and advancement of technologies that are not currently economical to deploy, the impacts and costs of which are not fully understood at this time. NIPSCO's electric generation transition is a key element of the Net Zero Goal. Our analysis and plan for execution, which is outlined in the NIPSCO 2021 Integrated Resource Plan, requires us to make a number of assumptions. These goals and underlying assumptions involve risks and uncertainties and are not guarantees. Should one or more of our underlying assumptions prove incorrect, our actual results and ability to achieve our emissions goal could differ materially from our expectations. Certain of the assumptions that could impact our ability to meet our emissions goal include, but are not limited to: the accuracy of current emission measurements, service territory size and capacity needs remaining in line with expectations; regulatory approval; impacts of future environmental regulations or legislation; impact of future GHG pricing regulations or legislation, including a future carbon tax or methane fee; price, availability and regulation of carbon offsets; price of fuel, such as natural gas; cost of energy generation technologies, such as wind and solar, natural gas and storage solutions; adoption of alternative energy by the public, including adoption of electric vehicles; rate of technology innovation with regards to alternative energy resources; our ability to implement our modernization plans for our pipelines and facilities; the ability to complete and implement generation alternatives to NIPSCO's coal generation and retirement dates of NIPSCO's coal facilities by 2028; the ability to construct and/or permit new natural gas pipelines; the ability to procure resources needed to build at a reasonable cost, the lack of scarcity of resources and labor, project cancellations, construction delays or overruns and the ability to appropriately estimate costs of new generation; impact of any supply chain disruptions; and advancement of energy efficiencies. Any negative opinions with respect to these goals or our environmental practices, including any inability to achieve, or a scaling back of these goals, formed by regulators, customers, investors or legislators could harm our reputation and have an adverse effect on our financial condition.

FINANCIAL, ECONOMIC AND MARKET RISKS

We have substantial indebtedness which could adversely affect our financial condition.

Our business is capital intensive and we rely significantly on long-term debt to fund a portion of our capital expenditures and repay outstanding debt, and on short-term borrowings to fund a portion of day-to-day business operations. We had total consolidated indebtedness of $11,315.5 million outstanding as of December 31, 2022. Our substantial indebtedness could have important consequences. For example, it could:

- limit our ability to borrow additional funds or increase the cost of borrowing additional funds;
- reduce the availability of cash flow from operations to fund working capital, capital expenditures and other general corporate purposes;

- limit our flexibility in planning for, or reacting to, changes in the business and the industries in which we operate;
- lead parties with whom we do business to require additional credit support, such as letters of credit, in order for us to transact such business;
- place us at a competitive disadvantage compared to competitors that are less leveraged;
- increase vulnerability to general adverse economic and industry conditions; and
- limit our ability to execute on our growth strategy, which is dependent upon access to capital to fund our substantial infrastructure investment program.

Some of our debt obligations contain financial covenants related to debt-to-capital ratios and cross-default provisions. Our failure to comply with any of these covenants could result in an event of default, which, if not cured or waived, could result in the acceleration of outstanding debt obligations.

A drop in our credit ratings could adversely impact our cash flows, results of operation, financial condition and liquidity.

The availability and cost of credit for our businesses may be greatly affected by credit ratings. The credit rating agencies periodically review our ratings, taking into account factors such as our capital structure, earnings profile, and overall shifts in the economy or business environment. We are committed to maintaining investment grade credit ratings; however, there is no assurance we will be able to do so in the future. Our credit ratings could be lowered or withdrawn entirely by a rating agency if, in its judgment, the circumstances warrant. Any negative rating action could adversely affect our ability to access capital at rates and on terms that are attractive. A negative rating action could also adversely impact our business relationships with suppliers and operating partners, who may be less willing to extend credit or offer us similarly favorable terms as secured in the past under such circumstances.

Certain of our subsidiaries have agreements that contain “ratings triggers” that require increased collateral in the form of cash, a letter of credit or other forms of security for new and existing transactions if our credit ratings (including the standalone credit ratings of certain of our subsidiaries) are dropped below investment grade. These agreements are primarily for insurance purposes and for the physical purchase or sale of gas or power. As of December 31, 2022, the collateral requirement that would be required in the event of a downgrade below the ratings trigger levels would amount to approximately $85.7 million. In addition to agreements with ratings triggers, there are other agreements that contain “adequate assurance” or “material adverse change” provisions that could necessitate additional credit support such as letters of credit and cash collateral to transact business.

If our or certain of our subsidiaries’ credit ratings were downgraded, especially below investment grade, financing costs and the principal amount of borrowings would likely increase due to the additional risk of our debt and because certain counterparties may require additional credit support as described above. Such amounts may be material and could adversely affect our cash flows, results of operations and financial condition. Losing investment grade credit ratings may also result in more restrictive covenants and reduced flexibility on repayment terms in debt issuances, lower share price and greater stockholder dilution from common equity issuances, in addition to reputational damage within the investment community.

Adverse economic and market conditions, including increased inflation, increases in interest rates, recession or changes in investor sentiment could materially and adversely affect our business, results of operations, cash flows, financial condition and liquidity.

Deteriorating, sluggish or volatile economic conditions in our operating jurisdictions could adversely impact our ability to maintain or grow our customer base and collect revenues from customers, which could reduce our revenue or growth rate and increase operating costs. A continued economic downturn or recession, or slowing or stalled recovery from such economic downturn or recession, may have a material adverse effect on our business, financial condition, or results of operations.

We rely on access to the capital markets to finance our liquidity and long-term capital requirements, including expenditures for our utility infrastructure and to comply with future regulatory requirements, to the extent not satisfied by the cash flow generated by our operations. We have historically relied on long-term debt and on the issuance of equity securities to fund a portion of our capital expenditures and repay outstanding debt, and on short-term borrowings to fund a portion of day-to-day business operations. Actions to reduce inflation, including raising interest rates, increase our cost of borrowing, which in turn could make it more difficult to obtain financing for our operations or investments on favorable terms. Successful implementation of our long-term business strategies, including capital investment, is dependent upon our ability to access the capital and credit markets, including the banking and commercial paper markets, on competitive terms and rates. An economic downturn or uncertainty, market turmoil, changes in interest rates, changes in tax policy, challenges faced by financial institutions, changes in our credit ratings, or a change in investor sentiment toward us or the utilities industry generally could adversely affect our ability to raise additional capital or refinance debt. For example, because NIPSCO's current generating facilities substantially rely on coal for its operations, certain financial institutions may choose not to participate in our financing arrangements. In addition, large institutional investors may choose to sell or choose not to purchase our stock due to environmental, social and governance ("ESG") concerns or concerns regarding renewable energy supply chain challenges. Reduced access to capital markets, increased borrowing costs, and/or lower equity valuation levels could reduce future earnings per share and cash flows. In addition, any rise in interest rates may lead to higher borrowing costs, which may adversely impact reported earnings, cost of capital and capital holdings.

If, in the future, we face limits to the credit and capital markets or experience significant increases in the cost of capital or are unable to access the capital markets, it could limit our ability to implement, or increase the costs of implementing, our business plan, which, in turn, could materially and adversely affect our results of operations, cash flows, financial condition and liquidity.

The COVID-19 pandemic has adversely impacted and may continue to adversely impact our business, results of operations, financial condition, liquidity and cash flows.

The COVID-19 pandemic has resulted in widespread impacts on the global economy and financial markets. The duration and ultimate impact of the COVID-19 pandemic on our business, results of operations and financial condition, including liquidity, capital and financing resources, will depend on numerous evolving factors and future developments, which are highly uncertain and cannot be predicted at this time. Such factors and developments may include the severity and duration of the COVID-19 pandemic, including whether there are periods of increased COVID-19 cases; the emergence of other new or more contagious variants that may render vaccines ineffective or less effective; disruption to our operations resulting from employee illnesses or any inability to attract, retain or motivate employees; the development, availability and administration of effective treatment or vaccines and the willingness of individuals to receive a vaccine; the extent and duration of the impact on the U.S. or global economy, including the pace and extent of recovery from the COVID-19 pandemic; and the actions that have been or may be taken by various governmental authorities in response to the COVID-19 pandemic.

Most of our revenues are subject to economic regulation and are exposed to the impact of regulatory rate reviews and proceedings.

Most of our revenues are subject to economic regulation at either the federal or state level. As such, the revenues generated by us are subject to regulatory review by the applicable federal or state authority. These rate reviews determine the rates charged to customers and directly impact revenues. Our financial results are dependent on frequent regulatory proceedings in order to ensure timely recovery of costs and investments. As described in more detail in the risk factor below, the outcomes of these proceedings are uncertain, potentially lengthy and could be influenced by many factors, some of which may be outside of our control, including the cost of providing service, the necessity of expenditures, the quality of service, regulatory interpretations, customer intervention, economic conditions and the political environment. Further, the rate orders are subject to appeal, which creates additional uncertainty as to the rates that will ultimately be allowed to be charged for services.

The actions of regulators and legislators could result in outcomes that may adversely affect our earnings and liquidity.

The rates that our electric and natural gas companies charge their customers are determined by their state regulatory commissions and by the FERC. These commissions also regulate the companies' accounting, operations, the issuance of certain securities and certain other matters. The FERC also regulates the transmission of electric energy, the sale of electric energy at wholesale, accounting, issuance of certain securities and certain other matters, including reliability standards through the North American Electric Reliability Corporation (NERC).

Under state and federal law, our electric and natural gas companies are entitled to charge rates that are sufficient to allow them an opportunity to recover their prudently incurred operating and capital costs and a reasonable rate of return on invested capital, to attract needed capital and maintain their financial integrity, while also protecting relevant public interests. Our electric and natural gas companies are required to engage in regulatory approval proceedings as a part of the process of establishing the terms and rates for their respective services. Each of these companies prepares and submits periodic rate filings with their respective regulatory commissions for review and approval, which allows for various entities to challenge our current or future rates, structures or mechanisms and could alter or limit the rates we are allowed to charge our customers. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups, and various consumers of energy, who have differing concerns. Any change in rates, including changes in allowed rate of return, are subject to regulatory approval proceedings that can be contentious, lengthy, and subject to appeal. This may lead to uncertainty as to the ultimate result of those proceedings. Established rates are also subject to subsequent prudency reviews by state regulators, whereby various portions of rates could be adjusted, subject to refund or disallowed, including cost recovery mechanisms. The ultimate outcome and timing of regulatory rate proceedings could have a significant effect on our ability to recover costs or earn an adequate return. Adverse decisions in our proceedings could adversely affect our financial position, results of operations and cash flows.

There can be no assurance that regulators will approve the recovery of all costs incurred by our electric and natural gas companies, including costs for construction, operation and maintenance, and compliance with current and future changes in environmental, federal pipeline safety, critical infrastructure and cyber security laws and regulations. Challenges arise with state regulators on inflationary pricing for electric and gas materials and potential price increases, ensuring that updated pricing for electric and gas materials is included in plans and regulatory assumptions, and ensuring there is a regulatory recovery model for emergency inventory stock. There is debate among state regulators and other stakeholders over how to transition to a decarbonized economy and prudency arguments relative to investing in natural gas assets when the depreciable life of the assets may be shortened due to electrification. The inability to recover a significant amount of operating costs could have an adverse effect on a company's financial position, results of operations and cash flows.

Changes to rates may occur at times different from when costs are incurred. Additionally, catastrophic events at other utilities could result in our regulators and legislators imposing additional requirements that may lead to additional costs for the companies.

In addition to the risk of disallowance of incurred costs, regulators may also impose downward adjustments in a company's allowed ROE as well as assess penalties and fines. Regulators may reduce ROE to mitigate potential customer bill increases due to items unrelated to capital investments such as potential increases in taxes and incremental costs related to COVID-19. These actions would have an adverse effect on our financial position, results of operations and cash flows.

Our electric business is subject to mandatory reliability and critical infrastructure protection standards established by NERC and enforced by the FERC. The critical infrastructure protection standards focus on controlling access to critical physical and cybersecurity assets. Compliance with the mandatory reliability standards could subject our electric utilities to higher operating costs. In addition, compliance with PHMSA regulations could subject our gas utilities to higher operating costs. If our businesses are found to be in noncompliance, we could be subject to sanctions, including substantial monetary penalties, or damage to our reputation.

Changes in tax laws, as well as the potential tax effects of business decisions, could negatively impact our business, results of operations (including our expected project returns from our planned renewable energy projects), financial condition and cash flows.

Our business operations are subject to economic conditions in certain industries.

Business operations throughout our service territories have been and may continue to be adversely affected by economic events at the national and local level where our businesses operate. In particular, sales to large industrial customers, such as those in the steel, oil refining, industrial gas and related industries, are impacted by economic downturns and recession; geographic or technological shifts in production or production methods; and consumer demand for environmentally friendly products and practices. The U.S. manufacturing industry continues to adjust to changing market conditions including international competition, inflation and increasing costs, and fluctuating demand for its products. In addition, our results of operations are negatively impacted by lower revenues resulting from higher bankruptcies, predominately focused on commercial and industrial customers not able to sustain operations through the economic disruptions related to the pandemic.

We are exposed to risk that customers will not remit payment for delivered energy or services, and that suppliers or counterparties will not perform under various financial or operating agreements.

Our extension of credit is governed by a Corporate Credit Risk Policy, involves considerable judgment by our employees and is based on an evaluation of a customer or counterparty's financial condition, credit history and other factors. We monitor our credit risk exposure by obtaining credit reports and updated financial information for customers and suppliers, and by evaluating the financial status of our banking partners and other counterparties by reference to market-based metrics such as credit default swap pricing levels, and to traditional credit ratings provided by the major credit rating agencies. Adverse economic conditions result in an increase in defaults by customers, suppliers and counterparties.

ITEM 1A. RISK FACTORS

NISOURCE INC.

We are a holding company and are dependent on cash generated by our subsidiaries to meet our debt obligations and pay dividends on our stock.

We are a holding company and conduct our operations primarily through our subsidiaries, which are separate and distinct legal entities. Substantially all of our consolidated assets are held by our subsidiaries. Accordingly, our ability to meet our debt obligations or pay dividends on our common stock and preferred stock is largely dependent upon cash generated by these subsidiaries. In the event a major subsidiary is not able to pay dividends or transfer cash flows to us, our ability to service our debt obligations or pay dividends could be negatively affected.

The trading prices for our Equity Units, initially consisting of Corporate Units, and related treasury units and Series C Mandatory Convertible Preferred Stock, are expected to be affected by, among other things, the trading prices of our common stock, the general level of interest rates and our credit quality.

The trading prices of the Equity Units, initially consisting of Corporate Units, which are listed on the New York Stock Exchange, and the related treasury units and Series C Mandatory Convertible Preferred Stock in the secondary market, are expected to be affected by, among other things, the trading prices of our common stock, the general level of interest rates and our credit quality. It is impossible to predict whether the price of our common stock or interest rates will rise or fall. The price of our common stock could be subject to wide fluctuations in the future in response to many events or factors, including those discussed in the risk factors herein, many of which events and factors are beyond our control. Fluctuations in interest rates may give rise to arbitrage opportunities based upon changes in the relative value of the common stock underlying the purchase contracts and of the other components of the Equity Units. Any such arbitrage could, in turn, affect the trading prices of the Corporate Units, treasury units, mandatory convertible preferred stock and our common stock.

The early settlement right triggered under certain circumstances and the supermajority rights of the Series C Mandatory Convertible Preferred Stock following a fundamental change, could discourage a potential acquirer.

The fundamental change early settlement right with respect to the purchase contracts triggered under certain circumstances by a fundamental change and the supermajority voting rights of the Series C Mandatory Convertible Preferred Stock in connection with certain fundamental change transactions jointly could discourage a potential acquirer, including potential acquirers that would otherwise seek a transaction with us that would be attractive to our investors.

Our Equity Units, initially consisting of Corporate Units, and related Series C Mandatory Convertible Preferred Stock, and the issuance and sale of common stock in settlement of the purchase contracts and conversion of mandatory convertible preferred stock, may all adversely affect the market price of our common stock and will cause dilution to our stockholders.

The market price of our common stock is likely to be influenced by our Equity Units, initially consisting of Corporate Units, and related mandatory convertible preferred stock. For example, the market price of our common stock could become more volatile and could be depressed by:

- investors' anticipation of the sale into the market of a substantial number of additional shares of our common stock issued upon settlement of the purchase contracts or conversion of our mandatory convertible preferred stock;
- possible sales of our common stock by investors who view our Equity Units, initially consisting of Corporate Units, or related mandatory convertible preferred stock as a more attractive means of equity participation in us than owning shares of our common stock; and
- hedging or arbitrage trading activity that may develop involving our Equity Units, initially consisting of Corporate Units, or related mandatory convertible preferred stock and our common stock.

In addition, we cannot predict the effect that future issuances or sales of our common stock, if any, including those made upon the settlement of the purchase contracts or conversion of the mandatory convertible preferred stock, may have on the market price for our common stock.

Our Equity Units, initially consisting of Corporate Units, and the issuance and sale of substantial amounts of common stock, including issuances and sales upon the settlement of the purchase contracts or conversion of the mandatory convertible preferred stock, could adversely affect the market price of our common stock and will cause dilution to our stockholders.

Capital market performance and other factors may decrease the value of benefit plan assets, which then could require significant additional funding and impact earnings.

NISOURCE INC.

The performance of the capital markets affects the value of the assets that are held in trust to satisfy future obligations under defined benefit pension and other postretirement benefit plans. We have significant obligations in these areas and hold significant assets in these trusts. These assets are subject to market fluctuations and may yield uncertain returns, which fall below our projected rates of return. A decline in the market value of assets may increase the funding requirements of the obligations under the defined benefit pension plans. Additionally, changes in interest rates affect the liabilities under these benefit plans; as interest rates decrease, the liabilities increase, which could potentially increase funding requirements. Further, the funding requirements of the obligations related to these benefits plans may increase due to changes in governmental regulations and participant demographics, including increased numbers of retirements or longer life expectancy assumptions, as well as voluntary early retirements. In addition, lower asset returns result in increased expenses. Ultimately, significant funding requirements and increased pension or other postretirement benefit plan expense could negatively impact our results of operations and financial position.

We have significant goodwill. Any future impairments of goodwill could result in a significant charge to earnings in a future period and negatively impact our compliance with certain covenants under financing agreements.

In accordance with GAAP, we test goodwill for impairment at least annually and review our definite-lived intangible assets for impairment when events or changes in circumstances indicate its fair value might be below its carrying value. Goodwill is also tested for impairment when factors, examples of which include reduced cash flow estimates, a sustained decline in stock price or market capitalization below book value, indicate that the carrying value may not be recoverable.

A significant charge in the future could impact the capitalization ratio covenant under certain financing agreements. We are subject to a financial covenant under our revolving credit facility and term credit agreement, which requires us to maintain a debt to capitalization ratio that does not exceed 70%. As of December 31, 2022, the ratio was 58.9%.

LITIGATION, REGULATORY AND LEGISLATIVE RISKS

The outcome of legal and regulatory proceedings, investigations, inquiries, claims and litigation related to our business operations may have a material adverse effect on our results of operations, financial position or liquidity.

We are involved in legal and regulatory proceedings, investigations, inquiries, claims and litigation in connection with our business operations, including those related to the Greater Lawrence Incident, the most significant of which are summarized in Note 19, "Other Commitments and Contingencies," in the Notes to Consolidated Financial Statements. Our insurance does not cover all costs and expenses that we have incurred relating to the Greater Lawrence Incident, and does not fully cover incidents that could occur in the future. Due to the inherent uncertainty of the outcomes of such matters, there can be no assurance that the resolution of any particular claim or proceeding would not have a material adverse effect on our results of operations, financial position or liquidity.

The Greater Lawrence Incident has materially adversely affected and may continue to materially adversely affect our financial condition, results of operations and cash flows and we may have continued financial liabilities related to the sale of the Massachusetts Business.

In connection with the Greater Lawrence Incident, we have incurred and will incur various costs and expenses. While we have recovered the full amount of our liability insurance coverage available under our policies, total expenses related to the incident exceeded such amount. Expenses in excess of our liability insurance coverage have materially adversely affected and may continue to materially adversely affect our results of operations, cash flows and financial position. We may also incur additional costs associated with the Greater Lawrence Incident, beyond the amount currently anticipated, including in connection with civil litigation. Additionally, it may be difficult to determine whether a claim for damages from a third party related to the Massachusetts Business or the Greater Lawrence Incident is our responsibility or Eversource’s, and we may expend substantial resources trying to determine whether we or Eversource has responsibility for the claim. Further, state or federal legislation may be enacted that would require us to incur additional costs by mandating various changes, including changes to our operating practice standards for natural gas distribution operations and safety. In addition, if it is determined in other matters that we did not comply with applicable statutes, regulations or rules in connection with the operations or maintenance of our natural gas system, and we are ordered to pay additional amounts in penalties, or other amounts, our financial condition, results of operations, and cash flows could be materially and adversely affected.

Our settlement with the U.S. Attorney’s Office in respect of federal charges in connection with the Greater Lawrence Incident may expose us to further penalties, liabilities and private litigation, and may impact our operations.

On February 26, 2020, the Company entered into a DPA and Columbia of Massachusetts entered into a plea agreement with the U.S. Attorney’s Office to resolve the U.S. Attorney’s Office’s investigation relating to the Greater Lawrence Incident, which was subsequently approved by the United States District Court for the District of Massachusetts. The agreements impose various compliance and remedial obligations on the Company and Columbia of Massachusetts. Failure to comply with the terms of these agreements could result in further enforcement action by the U.S. Attorney's Office, expose the Company and Columbia of Massachusetts to penalties, financial or otherwise, and subject the Company to further private litigation, each of which could impact our operations and have a material adverse effect on our business.

Our businesses are subject to various federal, state and local laws, regulations, tariffs and policies. We could be materially adversely affected if we fail to comply with such laws, regulations, tariffs and policies or with any changes in or new interpretations of such laws, regulations, tariffs and policies.

Our businesses are subject to various federal, state and local laws, regulations, tariffs and policies, including, but not limited to, those relating to natural gas pipeline safety, employee safety, the environment and our energy infrastructure. In particular, we are subject to significant federal, state and local regulations applicable to utility companies, including regulations by the various utility commissions in the states where we serve customers. These regulations significantly influence our operating environment, may affect our ability to recover costs from utility customers, and cause us to incur substantial compliance and other costs. Existing laws, regulations, tariffs and policies may be revised or become subject to new interpretations, and new laws, regulations, tariffs and policies may be adopted or become applicable to us and our operations. In some cases, compliance with new laws, regulations, tariffs and policies increases our costs or risks of liability. Supply chain constraints may challenge our ability to remain in compliance if we cannot obtain the materials that we need to operate our business in a compliant manner. If we fail to comply with laws, regulations and tariffs applicable to us or with any changes in or new interpretations of such laws, regulations, tariffs or policies, our financial condition, results of operations, regulatory outcomes and cash flows may be materially adversely affected.

Our businesses are regulated under numerous environmental laws and regulations. The cost of compliance with these laws and regulations, and changes to or additions to, or reinterpretations of the laws and regulations, could be significant, and the cost of compliance may not be recoverable. Liability from the failure to comply with existing or changed laws and regulations could have a material adverse effect on our business, results of operations, cash flows and financial condition.

Our businesses are subject to extensive federal, state and local environmental laws and rules that regulate, among other things, air emissions, water usage and discharges, GHG and waste products such as CCR. Compliance with these legal obligations require us to make significant expenditures for installation of pollution control equipment, remediation, environmental monitoring, emissions fees, and permits at many of our facilities. Furthermore, if we fail to comply with environmental laws and regulations or are found to have caused damage to the environment or persons, that failure or harm may result in the assessment of civil or criminal penalties and damages against us, injunctions to remedy the failure or harm, and the inability to operate facilities as designed and intended.

Existing environmental laws and regulations may be revised and new laws and regulations may be adopted or become applicable to us, with an increasing focus on the impact of coal and natural gas facilities that may result in significant additional expense and operating restrictions on our facilities, which may not be fully recoverable from customers and could materially affect the continued economic viability of our facilities.

An area of significant uncertainty and risk are potential changes to the laws concerning emission of GHG. While we continue to execute our plan to reduce our Scope 1 GHG emissions through the retirement of coal-fired electric generation, increased sourcing of renewable energy, priority pipeline replacement, leak detection and repair, and other methods, and while we have set a Net Zero Goal, GHG emissions are anticipated to be associated with energy delivery for many years. Future GHG legislation and/or regulation related to the generation of electricity or the extraction, production, distribution, transmission, storage and end use of natural gas could materially impact our gas supply, financial position, financial results and cash flows.

Another area of significant uncertainty and risk are the regulations concerning CCR. The EPA has issued regulations and plans to promulgate additional regulations concerning the management, transformation, transportation and storage of CCRs. NIPSCO is also incurring or will incur costs associated with closing, corrective action, and ongoing monitoring of certain CCR impoundments. We have two pending petitions at the Indiana Utility Regulatory Commission (IURC) seeking recovery of ash pond closure costs related to federal regulations governing CCRs at the Michigan City and R.M. Schahfer Generating Stations and believe there is supportive Indiana law authorizing such recovery. Further, a release of CCR to the environment could result in remediation costs, penalties, claims, litigation, increased compliance costs, and reputational damage.

We currently have a pending application with the EPA to continue operation of a CCR impoundment that is tied to operation of R.M. Schahfer Generating Station Units 17 and 18 to the end of 2025, with the CCR impoundment closing by October 2028. In proposed and final EPA actions denying continued operation of CCR impoundments at other utilities, EPA said that CCR impoundments should cease receipt of CCRs within 135 days of final EPA action unless certain conditions are demonstrated, such as potential reliability issues. In the event that approval is not obtained, future operations could be impacted.

The actual future expenditures to achieve environmental compliance depends on many factors, including the nature and extent of impact, the method of improvement, the cost of raw materials, contractor costs, and requirements established by environmental authorities. Changes in costs and the ability to recover under regulatory mechanisms could affect our financial position, financial results and cash flows.

Changes in taxation and the ability to quantify such changes as well as challenges to tax positions could adversely affect our financial results.

We are subject to taxation by the various taxing authorities at the federal, state and local levels where we do business. Legislation or regulation which could affect our tax burden could be enacted by any of these governmental authorities. The IRA imposed a 15 percent minimum tax rate on book earnings for corporations with higher than $1 billion of annual income, along with a 1 percent excise tax on corporate stock repurchases while providing tax incentives to promote various clean energy initiatives. We are currently assessing the potential impact of these legislative changes. The outcome of regulatory proceedings regarding the extent to which the effect of a change in corporate tax rate will impact customers and the time period over which the impact will occur could significantly impact future earnings and cash flows. Separately, a challenge by a taxing authority, changes in taxing authorities' administrative interpretations, decisions, policies and positions, our ability to utilize tax benefits such as carryforwards or tax credits, or a deviation from other tax-related assumptions may cause actual financial results to deviate from previous estimates.

ITEM 1B. UNRESOLVED STAFF COMMENTS

NISOURCE INC.

None.

ITEM 2. PROPERTIES

Discussed below are the principal properties held by us and our subsidiaries as of December 31, 2022.

Gas Distribution Operations
Refer to Item 1, "Business - Gas Distribution Operations," of this report for further information on Gas Distribution Operations properties.

Electric Operations
Refer to Item 1, "Business - Electric Operations," of this report for further information on Electric Operations properties.

Corporate and Other Operations
We own the Southlake Complex, our 325,000 square foot headquarters building located in Merrillville, Indiana.

Character of Ownership
Our principal properties and our subsidiaries' principal properties are owned free from encumbrances, subject to minor exceptions, none of which are of such a nature as to impair substantially the usefulness of such properties. Many of our subsidiary offices in various communities served are occupied under leases. All properties are subject to routine liens for taxes, assessments and undetermined charges (if any) incidental to construction. It is our practice to regularly pay such amounts, as and when due, unless contested in good faith. In general, the electric lines, gas pipelines and related facilities are located on land not owned by us or our subsidiaries, but are covered by necessary consents of various governmental authorities or by appropriate rights obtained from owners of private property. We do not, however, generally have specific easements from the owners of the property adjacent to public highways over, upon or under which our electric lines and gas distribution pipelines are located. At the time each of the principal properties was purchased, a title search was made. In general, no examination of titles as to rights-of-way for electric lines, gas pipelines or related facilities was made, other than examination, in certain cases, to verify the grantors’ ownership and the lien status thereof.

ITEM 3. LEGAL PROCEEDINGS

For a description of our legal proceedings, see Note 19, "Other Commitments and Contingencies - C. Legal Proceedings," in the Notes to Consolidated Financial Statements.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

NISOURCE INC.

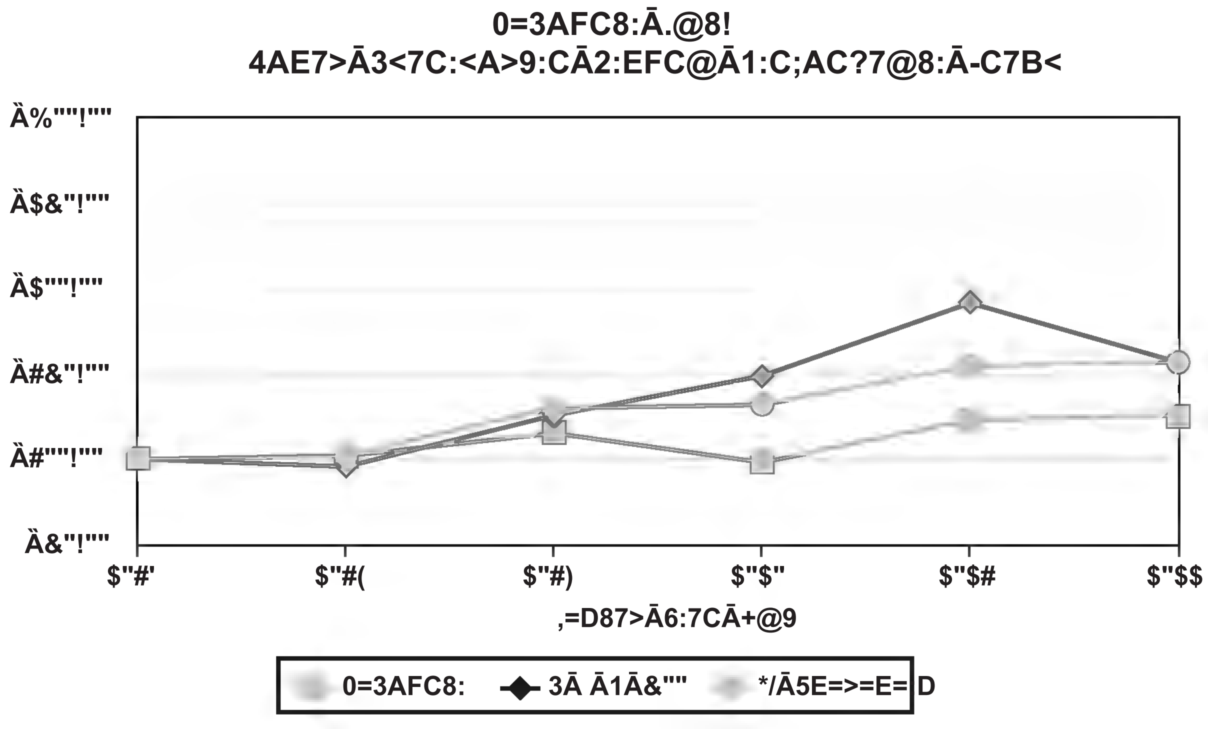
NiSource's common stock is listed and traded on the New York Stock Exchange under the symbol "NI."

Holders of shares of NiSource's common stock are entitled to receive dividends if and when declared by the Board out of funds legally available, subject to the prior dividend rights of holders of our preferred stock or the depositary shares representing such preferred stock outstanding, and if full dividends have not been declared and paid on all outstanding shares of preferred stock in any dividend period, no dividend may be declared or paid or set aside for payment on our common stock. The policy of the Board has been to declare cash dividends on a quarterly basis payable on or about the 20th day of February, May, August, and November. At its January 26, 2023 meeting, the Board declared a quarterly common dividend of $0.250 per share, payable on February 17, 2023 to holders of record on February 7, 2023.

Although the Board currently intends to continue the payment of regular quarterly cash dividends on common shares, the timing and amount of future dividends will depend on the earnings of NiSource's subsidiaries, their financial condition, cash requirements, regulatory restrictions, any restrictions in financing agreements and other factors deemed relevant by the Board. There can be no assurance that NiSource will continue to pay such dividends or the amount of such dividends.

As of February 15, 2023, NiSource had 16,572 common stockholders of record and 412,507,944 shares outstanding.

The graph below compares the cumulative total shareholder return of NiSource's common stock for the period commencing December 31, 2017 and ending December 31, 2022 with the cumulative total return for the same period of the S&P 500 and the Dow Jones Utility indices.



The foregoing performance graph is being furnished as part of this annual report solely in accordance with the requirement under Rule 14a-3(b)(9) to furnish stockholders with such information, and therefore, shall not be deemed to be filed or incorporated by reference into any filings by NiSource under the Securities Act or the Exchange Act.

The total shareholder return for NiSource common stock and the two indices is calculated from an assumed initial investment of $100 and assumes dividend reinvestment.

Purchases of Equity Securities by Issuer and Affiliated Purchasers. For the three months ended December 31, 2022, no equity securities that are registered by NiSource Inc. pursuant to Section 12 of the Securities Exchange Act of 1934 were purchased by or on behalf of us or any of our affiliated purchasers.

ITEM 6. RESERVED

NISOURCE INC.

Not applicable.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

NISOURCE INC.

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EXECUTIVE SUMMARY

This Management's Discussion and Analysis of Financial Condition and Results of Operations ("Management's Discussion") includes management's analysis of past financial results and certain potential factors that may affect future results, potential future risks and approaches that may be used to manage those risks. See "Note regarding forward-looking statements" and Item 1A, "Risk Factors" at the beginning of this report for a list of factors that may cause results to differ materially.

This Management's Discussion is designed to provide an understanding of our operations and financial performance and should be read in conjunction with our Consolidated Financial Statements and related Notes to Consolidated Financial Statements in this annual report.

We are an energy holding company under the Public Utility Holding Company Act of 2005 whose subsidiaries are fully regulated natural gas and electric utility companies serving customers in six states. We generate substantially all of our operating income through these rate-regulated businesses, which are summarized for financial reporting purposes into two primary reportable segments: Gas Distribution Operations and Electric Operations.

Refer to the "Business" section under Item 1 of this annual report and Note 21, "Business Segment Information," in the Notes to Consolidated Financial Statements for further discussion of our regulated utility business segments.

Our goal is to develop strategies that benefit all stakeholders as we (i) embark on long-term infrastructure investment and safety programs to better serve our customers, (ii) align our tariff structures with our cost structure, and (iii) address changing customer conservation patterns. These strategies focus on improving safety and reliability, enhancing customer service, ensuring customer affordability and reducing emissions while generating sustainable returns. The safety of our customers, communities and employees remains our top priority. In 2022, NiSource achieved conformance certification to the American Petroleum Institute Recommended Practice 1173, which serves as the guiding practice for our SMS. This certification marks an important milestone for our SMS and NiSource's journey towards operational excellence. Additionally, we continue to pursue regulatory and legislative initiatives that will allow residential customers not currently on our system to obtain gas service in a cost effective manner.

2022 Overview: In 2022, we continued to make significant progress towards our strategic and financial goals and objectives. We completed the first full year of operating Indiana Crossroads Wind, and construction is near completion for two of our solar projects. In 2022, we filed four rate cases and resolved three, in Pennsylvania, Maryland, and the gas rate case in Indiana filed in 2021. In addition, the Ohio rate case was resolved in January 2023 and the Virginia rate case is anticipated to be resolved in the first quarter of 2023. These cases represent balanced outcomes supporting all stakeholders. Between our Gas Distribution and Electric Operating Segments, we added 25,000 customers. We also invested $1.6 billion in infrastructure modernization to enhance safe, reliable service, including replacement of 410 miles of distribution main and service lines, 48 miles of underground cable and 1,352 electric poles.

We also made advancements in key strategic initiatives, described in further detail below.

Your Energy, Your Future: Our plan to replace our coal generation capacity by the end of 2028 with primarily renewable resources, initiated through our 2018 Integrated Resource Plan ("2018 Plan") is well underway, and we are continually adjusting to the dynamic renewable energy landscape. As of December 31, 2022, we have executed and received IURC approval for BTAs and PPAs with a combined nameplate capacity of 1,950 MW and 1,380 MW, respectively, under the 2018 Plan. During 2022, we made significant progress on our first two solar BTAs and anticipate completion of these projects and tax equity financing in 2023. We have also taken contractual actions on a number of our other renewable projects to address the timing of these projects as well as consider the broad market issues facing the industry. We remain on track to retire R.M Schahfer's remaining two coal units by the end of 2025. In August 2022, the IRA was signed into law. We are evaluating the impact of this legislation to our renewable projects with potential to drive increased value to customers as part of our expansion of renewable projects and generation transition strategy. However, the leveraging of the IRA will be considered on a project-by-project basis and evaluate several factors, both quantitative and qualitative, that results in the best position for project success as well as customer and company considerations. For additional information, see "Results and Discussion of Segment Operations - Electric Operations," in this Management's Discussion.

In 2021, we announced and filed with the IURC the Preferred Energy Resource Plan associated with our 2021 Integrated Resource Plan ("2021 Plan"). The 2021 Plan lays out a timeline to retire the Michigan City Generating Station by the end of 2028. The 2021 Plan calls for the replacement of the retiring units with a diverse portfolio of resources including demand side management resources, incremental solar, stand-alone energy storage and upgrades to existing facilities at the Sugar Creek Generating Station, among other steps. Additionally, the 2021 Plan calls for a natural gas peaking unit to replace existing vintage gas peaking units at the R.M. Schahfer Generating Station to support system reliability and resiliency, as well as upgrades to the transmission system to enhance our electric generation transition. The planned retirement of the two vintage gas peaking units at the R.M. Schahfer Generating Station is also expected to occur by the end of 2028. Final retirement dates for these units, as well as Michigan City, will be subject to MISO approval. We are continuing to evaluate potential projects under the 2021 Plan given the responses to our Request for Proposal issued in August 2022.

Transformation: The NiNext initiative, which commenced in 2020, focused on optimizing our workforce and advancing our operations. NiNext has been foundational in preparing for incremental, enterprise-wide investments to address inefficiencies in our current technology footprint, which stem primarily from a complex array of legacy systems. We plan to address these inefficiencies through our Enterprise Transformation Roadmap with investments in technology systems and infrastructure. As a result of these investments, we will deliver more modern, dependable, and secure IT systems backed with standardized processes to reduce the operating risks of our business, increase workforce efficiencies, and increase visibility to data which will be leveraged to drive risk-informed decisions. Our Enterprise Transformation Roadmap will position us to accomplish future strategic investments and aspirational goals.

Economic Environment: We are monitoring risks related to increasing order and delivery lead times for construction and other materials, increasing risk of unavailability of materials due to global shortages in raw materials, and risk of decreased construction labor productivity in the event of disruptions in the availability of materials. We are also seeing increasing prices associated with certain materials and supplies. To the extent that delays occur or our costs increase, our business operations, results of operations, cash flows, and financial condition could be materially adversely affected. For more information on supply chain impacts to our electric generation strategy, see "Results and Discussion of Segment Operations - Electric Operations," in this Management's Discussion.

Early in 2022, NIPSCO experienced a rail service shortage in deliveries of coal, particularly to its Michigan City Generating Station, and the primary rail carrier for that generating station was unable to provide assurance of adequate future service to maintain coal inventory. A lack of adequate coal deliveries to any of our coal-fired generating facilities for an extended period could deplete our inventories to a level that prevents the generating station from running, and NIPSCO would need to rely on market purchases of replacement power, which could increase the cost of electricity for NIPSCO's customers. NIPSCO believes these shortages have been resolved but continues to monitor deliveries of coal from its rail carriers. This did not have a material impact on our operations in 2022.

We are faced with increased competition for employee and contractor talent in the current labor market, which has resulted in increased costs to attract and retain talent. We are ensuring that we use all internal human capital programs (development, leadership enablement programs, succession, performance management) to promote retention of our current employees along with having a competitive and attractive appeal for potential recruits. With a focus on workforce planning, we are anticipating to evaluate our talent footprint for the future by creating flexible work arrangements where we can, to ensure we have the right people, in the right role, and at the right time. To the extent we are unable to execute on our workforce planning initiatives and experience increased employee and contractor costs, our business operations, results of operations, cash flows, and financial condition could be materially adversely affected.

We experienced an increase in natural gas costs as the spot market for natural gas substantially increased throughout much of 2022, followed by a decrease in the price of natural gas since November 2022. Nationally, levels of gas in storage were lower in 2022 compared to 2021, liquified natural gas exports to Europe continued at a steady pace, and domestic production saw a recent decline in demand. These factors drove increased volatility in the marketplace, which influenced customer bills throughout 2022. While production was increasing towards the end of 2022, weather changes have limited demand and decreased withdrawals, causing inventory balances to be higher compared to 2021. With this decline in price, we expect to see lower volatility and declining customer bills. For the year ended December 31, 2022, we did not see this volatility have a material impact on our results of operations. For more information on our commodity price impacts, see "Results and Discussion of Segment Operations - Gas Distribution Operations," and "Market Risk Disclosures."

Due to rising interest rates, we experienced higher interest expense in 2022 compared to 2021 associated with short-term borrowings. We continue to evaluate our financing plan to manage interest expense and exposure to rates. For more information on interest rate risk, see "Market Risk Disclosures".

For more information on global availability of materials for our renewable projects, see "Results and Discussion of Segment Operations - Electric Operations - Electric Supply and Generation Transition."

Summary of Consolidated Financial Results

A summary of our consolidated financial results for the years ended December 31, 2022, 2021 and 2020, are presented below:

Year Ended December 31, *(in millions, except per share amounts)*	**2022**	2021	2020	Favorable (Unfavorable) 2022 vs. 2021	Favorable (Unfavorable) 2021 vs. 2020
Operating Revenues	**$ 5,850.6**	$ 4,899.6	$ 4,681.7	$ 951.0	$ 217.9
Operating Expenses					
Cost of energy	**2,110.5**	1,392.3	1,109.3	(718.2)	(283.0)
Other Operating Expenses	**2,474.3**	2,500.4	3,021.6	26.1	521.2
Total Operating Expenses	**4,584.8**	3,892.7	4,130.9	(692.1)	238.2
Operating Income	**1,265.8**	1,006.9	550.8	258.9	456.1
Total Other Deductions, Net	**(309.4)**	(300.3)	(582.1)	(9.1)	281.8
Income Taxes	**164.6**	117.8	(17.1)	(46.8)	(134.9)
Net Income (Loss)	**791.8**	588.8	(14.2)	203.0	603.0
Net income (loss) attributable to noncontrolling interest	**(12.3)**	3.9	3.4	16.2	(0.5)
Net Income (Loss) attributable to NiSource	**804.1**	584.9	(17.6)	219.2	602.5
Preferred dividends	**(55.1)**	(55.1)	(55.1)	—	—
Net Income (Loss) Available to Common Shareholders	**749.0**	529.8	(72.7)	219.2	602.5
Basic Earnings (Loss) Per Share	**$ 1.84**	$ 1.35	$ (0.19)	$ 0.49	$ 1.54
Diluted Earnings (Loss) Per Share	**$ 1.70**	$ 1.27	$ (0.19)	$ 0.43	$ 1.46

The majority of the costs of energy in both segments are tracked costs that are passed through directly to the customer, resulting in an equal and offsetting amount reflected in operating revenues.

The increase in net income available to common shareholders during 2022 was primarily due to higher revenues from outcomes of gas base rate proceedings and regulatory capital programs, as well as an insurance settlement related to the Greater Lawrence Incident, offset by higher income taxes in 2022 compared to 2021.

For additional information on operating income variance drivers see "Results and Discussion of Segment Operations" for Gas and Electric Operations in this Management's Discussion.

Other Deductions, Net

The change in Other deductions, net in 2022 compared to 2021 is primarily driven by higher long-term and short-term debt interest in 2022 and lower non-service pension benefits partially offset by the interest rate swap settlement gain in 2022 and charitable contributions in 2021. See Note 15, "Long-Term Debt," Note 16, "Short-Term Borrowings," and Note 12, "Pension and Other Postemployment Benefits," in the Notes to Consolidated Financial Statements for additional information.

Income Taxes
The increase in income tax expense in 2022 compared to the same period in 2021 is primarily attributable to higher pre-tax income, offset by higher state flow through and the reduction of the Pennsylvania corporate income tax rate.

Refer to Note 11, "Income Taxes," in the Notes to Consolidated Financial Statements for additional information on income taxes and the change in the effective tax rate.

RESULTS AND DISCUSSION OF OPERATIONS

Presentation of Segment Information
Our operations are divided into two primary reportable segments: Gas Distribution Operations and Electric Operations. The remainder of our operations, which are not significant enough on a stand-alone basis to warrant treatment as an operating segment, are presented as "Corporate and Other" within the Notes to the Consolidated Financial Statements and primarily are comprised of interest expense on holding company debt, and unallocated corporate costs and activities.

NISOURCE INC.
Gas Distribution Operations

Financial and operational data for the Gas Distribution Operations segment for the years ended December 31, 2022, 2021 and 2020, are presented below:

				Favorable (Unfavorable)	
Year Ended December 31, *(in millions)*	**2022**	2021	2020	2022 vs. 2021	2021 vs. 2020
Operating Revenues	**$ 4,019.8**	$ 3,183.5	$ 3,140.1	$ 836.3	$ 43.4
Operating Expenses					
Cost of energy	**1,534.8**	962.7	794.2	(572.1)	(168.5)
Operation and maintenance	**1,045.3**	993.8	1,138.0	(51.5)	144.2
Depreciation and amortization	**415.9**	383.0	363.1	(32.9)	(19.9)
Loss (gain) on sale of fixed assets and impairments, net	**(103.9)**	8.7	412.4	112.6	403.7
Other taxes	**211.9**	217.8	233.3	5.9	15.5
Total Operating Expenses	**3,104.0**	2,566.0	2,941.0	(538.0)	375.0
Operating Income	**$ 915.8**	$ 617.5	$ 199.1	$ 298.3	$ 418.4
Revenues					
Residential	**$ 2,609.6**	$ 2,143.4	$ 2,110.6	$ 466.2	$ 32.8
Commercial	**942.4**	731.0	679.7	211.4	51.3
Industrial	**221.5**	197.2	213.8	24.3	(16.6)
Off-System	**192.9**	71.3	41.0	121.6	30.3
Other	**53.4**	40.6	95.0	12.8	(54.4)
Total	**$ 4,019.8**	$ 3,183.5	$ 3,140.1	$ 836.3	$ 43.4
Sales and Transportation (MMDth)					
Residential	**249.0**	231.2	249.5	17.8	(18.3)
Commercial	**181.3**	167.0	170.5	14.3	(3.5)
Industrial	**490.7**	507.1	538.1	(16.4)	(31.0)
Off-System	**32.3**	21.6	23.3	10.7	(1.7)
Other	**0.3**	0.3	0.3	—	—
Total	**953.6**	927.2	981.7	26.4	(54.5)
Heating Degree Days	**5,436**	5,002	5,097	434	(95)
Normal Heating Degree Days	**5,347**	5,427	5,485	(80)	(58)
% Colder (Warmer) than Normal	**2 %**	(8)%	(7)%		
% Colder (Warmer) than Prior Year	**9 %**	(2)%	(5)%		
Gas Distribution Customers					
Residential	**2,991,913**	2,970,157	2,954,478	21,756	15,679
Commercial	**254,436**	253,987	253,184	449	803
Industrial	**4,870**	4,921	4,968	(51)	(47)
Other	**3**	4	3	(1)	1
Total	**3,251,222**	3,229,069	3,212,633	22,153	16,436

NISOURCE INC.
Gas Distribution Operations (continued)

Comparability of operation and maintenance expenses, depreciation and amortization, and other taxes may be impacted by regulatory, depreciation and tax trackers that allow for the recovery in rates of certain costs.

The underlying reasons for changes in our operating revenues and expenses from 2022 to 2021 are presented in the respective tables below. Please refer to Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - Results and Discussion of Segment Operations - Gas Distribution Operations," of the Company's 2021 Annual Report on Form 10-K for discussion of underlying reasons for changes in our operating revenues and expenses for 2021 versus 2020.

		Favorable (Unfavorable)
Changes in Operating Revenues *(in millions)*		**2022 vs 2021**
New rates from base rate proceedings and regulatory capital programs	$	169.7
The effects of weather in 2022 compared to 2021		31.1
Higher revenue related to off system sales		8.8
The effects of customer growth		4.9
Higher revenue due to the effects of resuming common credit mitigation practices		3.5
Increased customer usage		2.3
Other		4.7
Change in operating revenues (before cost of energy and other tracked items)	$	225.0
Operating revenues offset in operating expense		
Higher cost of energy billed to customers		572.1
Higher tracker deferrals within operation and maintenance, depreciation, and tax		39.2
Total change in operating revenues	**$**	**836.3**

Weather
In general, we calculate the weather-related revenue variance based on changing customer demand driven by weather variance from normal heating degree days, net of weather normalization mechanisms. Our composite heating degree days reported do not directly correlate to the weather-related dollar impact on the results of Gas Distribution Operations. Heating degree days experienced during different times of the year or in different operating locations may have more or less impact on volume and dollars depending on when and where they occur. When the detailed results are combined for reporting, there may be weather-related dollar impacts on operations when there is not an apparent or significant change in our aggregated composite heating degree day comparison.

Throughput
The increase in total volumes sold and transported in 2022 compared to 2021 of 26.4 MMDth is primarily attributable to the effects of colder weather.

Commodity Price Impact
Cost of energy for the Gas Distribution Operations segment is principally comprised of the cost of natural gas used while providing transportation and distribution services to customers. All of our Gas Distribution Operations companies have state-approved recovery mechanisms that provide a means for full recovery of prudently incurred gas costs. These are tracked costs that are passed through directly to the customer, and the gas costs included in revenues are matched with the gas cost expense recorded in the period. The difference is recorded on the Consolidated Balance Sheets as under-recovered or over-recovered gas cost to be included in future customer billings. Therefore, increases in these tracked operating expenses are offset by increases in operating revenues and have essentially no impact on net income.

Certain Gas Distribution Operations companies continue to offer choice opportunities, where customers can choose to purchase gas from a third-party supplier, through regulatory initiatives in their respective jurisdictions.

NISOURCE INC.
Gas Distribution Operations (continued)

Changes in Operating Expenses *(in millions)*		**Favorable (Unfavorable) 2022 vs 2021**
Property insurance settlement related to the Greater Lawrence Incident	$	105.0
Lower NiSource Next program expenses		20.0
Lower other than income taxes primarily related to property tax expense		17.8
Loss on sale and expenses related to the Massachusetts Business in 2021		16.6
Higher depreciation and amortization expense		(35.1)
Higher outside services expenses		(12.2)
Higher employee and administrative related expenses		(10.0)
Higher fleet expenses		(5.5)
Rate case settlement impacts		(3.7)
Higher unrecoverable environmental remediation costs		(2.7)
Higher materials and supplies expense		(2.7)
Earnings test reserve adjustment in 2021		(2.5)
Other		(11.7)
Change in operating expenses (before cost of energy and other tracked items)	$	73.3
Operating expenses offset in operating revenue		
Higher cost of energy billed to customers		(572.1)
Higher tracker deferrals within operation and maintenance, depreciation, and tax		(39.2)
Total change in operating expense	**$**	**(538.0)**

Columbia of Massachusetts Asset Sale

On October 9, 2020, we completed the sale of our Massachusetts Business. In March 2021, we reached an agreement with Eversource regarding the final purchase price, including net working capital adjustments. This resulted in a pre-tax loss for the years ended December 31, 2022 and 2021 of zero and $6.8 million, respectively, based on asset and liability balances as of the close of the transaction on October 9, 2020, transaction costs and the final purchase price. The pre-tax loss is presented as "Loss (gain) on sale of assets, net" on the Statements of Consolidated Income (Loss).

NISOURCE INC.
Electric Operations

Financial and operational data for the Electric Operations segment for the years ended December 31, 2022, 2021 and 2020, are presented below:

				Favorable (Unfavorable)	
Year Ended December 31, *(in millions)*	**2022**	2021	2020	2022 vs. 2021	2021 vs. 2020
Operating Revenues	**$ 1,831.7**	$ 1,697.1	$ 1,536.6	$ 134.6	$ 160.5
Operating Expenses					
Cost of energy	**575.8**	429.7	315.2	(146.1)	(114.5)
Operation and maintenance	**486.2**	493.6	497.6	7.4	4.0
Depreciation and amortization	**362.9**	329.4	321.3	(33.5)	(8.1)
Gain on sale of fixed assets and impairments, net	**—**	(0.9)	—	(0.9)	0.9
Other taxes	**44.4**	57.5	53.7	13.1	(3.8)
Total Operating Expenses	**1,469.3**	1,309.3	1,187.8	(160.0)	(121.5)
Operating Income	**$ 362.4**	$ 387.8	$ 348.8	$ (25.4)	$ 39.0
Revenues					
Residential	**$ 592.4**	$ 568.0	$ 527.8	$ 24.4	$ 40.2
Commercial	**571.0**	534.9	480.3	36.1	54.6
Industrial	**561.4**	494.1	412.9	67.3	81.2
Wholesale	**13.5**	15.7	12.3	(2.2)	3.4
Other	**93.4**	84.4	103.3	9.0	(18.9)
Total	**$ 1,831.7**	$ 1,697.1	$ 1,536.6	$ 134.6	$ 160.5
Sales (Gigawatt Hours)					
Residential	**3,482.9**	3,546.8	3,484.0	(63.9)	62.8
Commercial	**3,682.4**	3,698.0	3,550.0	(15.6)	148.0
Industrial	**7,915.3**	8,253.7	7,480.3	(338.4)	773.4
Wholesale	**50.0**	124.7	83.6	(74.7)	41.1
Other	**89.5**	108.5	106.0	(19.0)	2.5
Total	**15,220.1**	15,731.7	14,703.9	(511.6)	1,027.8
Cooling Degree Days	**942**	1,020	900	(78)	120
Normal Cooling Degree Days	**831**	803	803	28	—
% Warmer than Normal	**13 %**	27 %	12 %		
% Warmer (Colder) than prior year	**(8)%**	13 %			
Electric Customers					
Residential	**424,735**	422,436	418,871	2,299	3,565
Commercial	**58,374**	58,010	57,435	364	575
Industrial	**2,130**	2,137	2,154	(7)	(17)
Wholesale	**710**	714	722	(4)	(8)
Other	**3**	2	2	1	—
Total	**485,952**	483,299	479,184	2,653	4,115

NiSource Inc.
Electric Operations (continued)

Comparability of operation and maintenance expenses and depreciation and amortization may be impacted by regulatory and depreciation trackers that allow for the recovery in rates of certain costs.

The underlying reasons for changes in our operating revenues and expenses from 2022 to 2021 are presented in the respective tables below. Please refer to Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - Results and Discussion of Segment Operations - Electric Operations," of the Company's 2021 Annual Report on Form 10-K for discussion of underlying reasons for changes in our operating revenues and expenses for 2021 versus 2020.

Changes in Operating Revenues *(in millions)*		**Favorable (Unfavorable) 2022 vs 2021**
PPA revenue from renewable JV projects, fully offset by JV operating expenses and noncontrolling interest net income (loss)	$	27.5
The effects of customer growth		4.6
Decreased fuel handling costs		4.0
New rates from regulatory capital and DSM programs		2.8
Decreased customer usage		(18.5)
Reduction in gross receipts tax, offset in operating expenses		(10.3)
FAC adjustment[1]		(8.0)
FAC over earnings reserve		(5.8)
The effects of weather in 2022 compared to 2021		(5.0)
Other		(2.4)
Change in operating revenues (before cost of energy and other tracked items)	$	(11.1)
Operating revenues offset in operating expense		
Higher cost of energy billed to customers		146.1
Lower tracker deferrals within operation and maintenance, depreciation and tax		(0.4)
Total change in operating revenues	**$**	**134.6**

[1]See Note 9, "Regulatory Matters," in the Notes to Consolidated Financial Statements for additional information.

Weather
In general, we calculate the weather-related revenue variance based on changing customer demand driven by weather variance from normal heating or cooling degree days. Our composite heating or cooling degree days reported do not directly correlate to the weather-related dollar impact on the results of Electric Operations. Heating or cooling degree days experienced during different times of the year may have more or less impact on volume and dollars depending on when they occur. When the detailed results are combined for reporting, there may be weather-related dollar impacts on operations when there is not an apparent or significant change in our aggregated composite heating or cooling degree day comparison.

Sales
NIPSCO's Electric Segment results remains closely linked to the performance of the steel industry. MWh sales to steel-related industries accounted for approximately 47.4% and 48.1% of the total industrial MWh sales for the years ended December 31, 2022 and 2021, respectively.

Commodity Price Impact
Cost of energy for the Electric Operations segment is principally comprised of the cost of coal, natural gas purchased for internal generation of electricity at NIPSCO, and the cost of power purchased from generators of electricity. NIPSCO has a state-approved recovery mechanism that provides a means for full recovery of prudently incurred costs of energy. The majority of these costs of energy are passed through directly to the customer, and the costs of energy included in operating revenues are matched with the cost of energy expense recorded in the period. The difference is recorded on the Consolidated Balance Sheets as under-recovered or over-recovered fuel cost to be included in future customer billings. Therefore, increases in these tracked operating expenses are offset by increases in operating revenues and have essentially no impact on net income.

NISOURCE INC.
Electric Operations (continued)

Changes in Operating Expenses *(in millions)*		**Favorable (Unfavorable) 2022 vs 2021**
Renewable JV project expenses, offset by JV operating revenues	$	(25.5)
Higher depreciation and amortization expense driven by the JV depreciation adjustment[1]		(15.7)
Effects of environmental recoveries in 2021		(6.5)
Higher outside services expenses		(5.7)
Expenses related to the accelerated retirement of the R.M. Schahfer Generating Station's coal Units 14 and 15 in 2021		13.2
Reduction in gross receipts tax, offset in operating revenues		10.3
Lower NiSource Next program expenses		8.1
Lower employee and administrative expenses		5.6
Other		1.9
Change in operating expenses (before cost of energy and other tracked items)	$	(14.3)
Operating expenses offset in operating revenue		
Higher cost of energy billed to customers		(146.1)
Lower tracker deferrals within operation and maintenance, depreciation and tax		0.4
Total change in operating expense	**$**	**(160.0)**

[1]See Note 9, "Regulatory Matters," in the Notes to Consolidated Financial Statements for additional information.

Electric Supply and Generation Transition

NIPSCO continues to execute on an electric generation transition consistent with the 2018 Plan, which outlines the path to retire the remaining two coal units at Schahfer by the end of 2025 and the remaining coal-fired generation by the end of 2028, to be replaced by lower-cost, reliable and cleaner options. See "Project Status" discussion, below, and "Liquidity and Capital Resources" in this Management's Discussion for anticipated barriers to the success of our electric generation transition and additional information on our capital investment spend.

NIPSCO continues to work with the EPA and the Indiana Department of Environmental Management to obtain administrative approvals associated with the operation of R.M. Schahfer's remaining two coal units beyond 2023. In the event that the approvals are not obtained, future operations could be impacted. We cannot estimate the financial impact on us if these approvals are not obtained.

The current replacement plan primarily includes renewable sources of energy, including wind, solar, and battery storage to be obtained through a combination of NIPSCO ownership and PPAs. NIPSCO has sold, and may in the future sell, renewable energy credits from this generation to third parties to offset customer costs. NIPSCO has executed several PPAs to purchase 100% of the output from renewable generation facilities at a fixed price per MWh. Each facility supplying the energy will have an associated nameplate capacity, and payments under the PPAs will not begin until the associated generation facility is constructed by the owner/seller. NIPSCO has also executed several BTAs with developers to construct renewable generation facilities.

Three wind projects have been placed into service, totaling approximately 804 MW of nameplate capacity. All announced projects below have received IURC approval. During 2022, NIPSCO amended certain of its BTAs and PPAs. NIPSCO is discussing potentially amending other BTAs and PPAs. Any amendments that result in increased project costs may require additional approval by the IURC in order to obtain recovery for increased costs. Our current replacement program will be augmented by the Preferred Energy Resource Plan outlined in our 2021 Integrated Resource Plan. See "Executive Summary - Your Energy, Your Future" in this Management's Discussion for additional information.

NISOURCE INC.
Electric Operations (continued)

Project Name	Transaction Type	Technology	Nameplate Capacity (MW)	Storage Capacity (MW)
Dunn's Bridge I(1)	BTA	Solar	265	—
Indiana Crossroads Solar(1)	BTA	Solar	200	—
Dunn's Bridge II(1)	BTA	Solar & Storage	435	75
Cavalry(1)	BTA	Solar & Storage	200	60
Fairbanks(1)	BTA	Solar	250	—
Elliott(1)	BTA	Solar	200	—
Indiana Crossroads II	15 year PPA	Wind	204	—
Brickyard	20 year PPA	Solar	200	—
Greensboro	20 year PPA	Solar & Storage	100	30
Gibson	22 year PPA	Solar	280	—
Green River	20 year PPA	Solar	200	—

(1) Ownership of the facilities will be transferred to JVs whose members are expected to include NIPSCO and an unrelated tax equity partner.

Project Status. Our contract amendments with certain solar agreements will result in the majority of our remaining projects, and investments, being placed in service between 2023 and 2025. These amendments also formally address inflationary cost pressures communicated from the developers of our solar and storage projects that are primarily due to (i) unavailability of solar panels and other uncertainties related to the pending U.S. Department of Commerce investigation on Antidumping and Countervailing Duties petition filed by a domestic solar manufacturer (the "DOC Investigation"), (ii) the U.S. Department of Homeland Security's June 2021 Withhold Release Order on silica-based products made by Hoshine Silicon Industry Co., Ltd./ Uyghur Forced Labor Prevention Act, (iii) Section 201 Tariffs and (iv) persistent general global supply chain and labor availability issues. We are also monitoring the developers of our renewable energy projects related to local permitting processes and obtaining interconnection rights. Preliminary findings from the DOC Investigation were released in December 2022, with a final decision expected in May 2023. The resolution of these issues, including the final conclusion of the DOC Investigation will determine which, if any, of our solar projects will be subject to any tariffs imposed.

In June 2022, the Biden Administration announced a 24-month tariff relief on solar panels subject to the ongoing U.S. Department of Commerce investigation and authorized the use of the Defense Production Act, to accelerate domestic production of clean energy technologies, including solar panel parts.

NISOURCE INC.

Liquidity and Capital Resources

We continually evaluate the availability of adequate financing to fund our ongoing business operations, working capital and core safety and infrastructure investment programs. Our financing is sourced through cash flow from operations and the issuance of debt and/or equity. External debt financing is provided primarily through the issuance of long-term debt, accounts receivable securitization programs and our $1.5 billion commercial paper program, which is backstopped by our committed revolving credit facility with a total availability from third-party lenders of $1.85 billion. On December 20, 2022, we entered into a $1.0 billion term credit agreement that matures on December 19, 2023. On February 18, 2022, we amended our revolving credit agreement to, among other things, extend its term to February 18, 2027. The commercial paper program and credit facility provide cost-effective, short-term financing until it can be replaced with a balance of long-term debt and equity financing that achieves our desired capital structure. On June 10, 2022, we completed the issuance and sale of $350.0 million of 5.00% senior unsecured notes maturing in 2052, which resulted in approximately $344.6 million of net proceeds after discount and debt issuance costs. We intend to disburse an amount equal to the net proceeds of the notes to finance, in whole or in part, the acquisition of our 302 MW Indiana Crossroads Wind project and 102 MW Rosewater Wind project from the project developer. On November 7, 2022, we announced that we intend to pursue the sale of a minority interest in our NIPSCO business unit. We utilize an ATM equity program that allows us to issue and sell shares of our common stock up to an aggregate issuance of $750.0 million through December 31, 2023. As of December 31, 2022, the ATM program had approximately $300.0 million of equity available for issuance. We also expect to remarket the Series C Mandatory Convertible Preferred Stock prior to December 1, 2023, which could result in additional cash proceeds. See Note 13, "Equity," in the Notes to Consolidated Financial Statements for more information on our ATM program and Equity Units.

We believe these sources provide adequate capital to fund our operating activities and capital expenditures in 2023 and beyond.

Greater Lawrence Incident. As discussed in Part I, Item 1A, "Risk Factors," and in Note 19, "Other Commitments and Contingencies," in the Notes to Consolidated Financial Statements, due to the inherent uncertainty of litigation, there can be no assurance that the outcome or resolution of any particular claim related to the Greater Lawrence Incident will not continue to have an adverse impact on our cash flows. Through income generated from operating activities, amounts available under the short-term revolving credit facility, and our ability to access capital markets, we believe we have adequate capital available to settle remaining anticipated claims associated with the Greater Lawrence Incident.

Operating Activities

Net cash from operating activities for the year ended December 31, 2022 was $1,409.4 million, an increase of $191.5 million from 2021. This increase was primarily driven by a year over year increase in revenue and collection of under-recovered gas and fuel cost from the prior year. This was offset by increased cash outflows related to inventory purchases year over year due to higher gas costs.

Investing Activities

Net cash used for investing activities for the year ended December 31, 2022 was $2,570.2 million, an increase of $365.3 million from 2021. Our current year investing activities were comprised of increased capital expenditures related to system growth and reliability as well as payments to renewable generation asset developers related to Dunn's Bridge I and Indiana Crossroads Solar milestone payments. This was offset by the property insurance settlement related to the Greater Lawrence Incident.

NISOURCE INC.

Capital Expenditures. The table below reflects actual capital expenditures and certain other investing activities by segment for 2022.

(in millions)	**Actual 2022**
Gas Distribution Operations	
System Growth and Tracker	**$ 1,266.1**
Maintenance	**329.7**
Total Gas Distribution Operations[1]	**1,595.8**
Electric Operations	
System Growth and Tracker	**345.0**
Maintenance	**164.2**
Generation Transition Investments	**31.4**
Total Electric Operations[1]	**540.6**
Corporate and Other Operations - Maintenance[1]	**161.6**
Total Capital Expenditures[2]	**$ 2,298.0**

[1]Amounts differ from those presented in Note 21, "Business Segment Information," in the Notes to Consolidated Financial Statements due to the allocation of Corporate and Other Maintenance Costs to the Gas Distribution and Electric Operations segments.
[2]Amounts differ from those presented on the Statements of Consolidated Cash Flows primarily due to the capitalized portion of the Corporate Incentive Plan payout, inclusion of capital expenditures included in current liabilities and AFUDC Equity.

In addition to these capital expenditures, we made $323.9 million of capital investments in the form of milestone payments to the renewable generation asset developer.

We expect to make capital investments totaling approximately $15 billion during the 2023-2027 period related to infrastructure modernization, generation transition and renewables and customer growth for the next five years:

(in billions)	**2022 Actual**	**2023 Estimated**	**2024 Estimated**	**2025 Estimated**	**2026 Estimated**	**2027 Estimated**
Capital Investments	$2.6	$3.3 - 3.6	$2.6 - 2.9	$3.1 - 3.4	$2.7 - 3.0	$ 2.7 - 3.0

Regulatory Capital Programs. We replace pipe and modernize our gas infrastructure to enhance safety and reliability and reduce leaks. An ancillary benefit of these programs is the reduction of GHG emissions. In 2022, we continued to move forward on core infrastructure and environmental investment programs supported by complementary regulatory and customer initiatives across all six states of our operating area.

NISOURCE INC.

The following table describes the most recent vintage of our regulatory programs to recover infrastructure replacement and other federally mandated compliance investments currently in rates or pending commission approval:

(in millions)

Company	Program	Incremental Revenue	Incremental Capital Investment	Investment Period	Costs Covered[1]	Rates Effective
Columbia of Ohio[2]	IRP - 2022	$ 25.0	$ 232.9	1/21-12/21	Replacement of (1) hazardous service lines, (2) cast iron, wrought iron, uncoated steel, and bare steel pipe, (3) natural gas risers prone to failure and (4) installation of AMR devices.	May 2022
Columbia of Ohio[2]	CEP - 2022	$ 32.2	$ 253.5	1/21-12/21	Assets not included in the IRP.	September 2022
NIPSCO - Gas[3]	TDSIC 4	$ 0.5	$ 77.5	7/21-12/21	New or replacement projects undertaken for the purpose of safety, reliability, system modernization or economic development.	July 2022
NIPSCO - Gas[4]	FMCA 1	$ 1.5	$ 14.1	10/21-3/22	Project costs to comply with federal mandates.	October 2022
NIPSCO - Gas[4]	FMCA 2	$ 5.3	$ 38.2	4/22-9/22	Project costs to comply with federal mandates.	April 2023
Columbia of Virginia[5]	SAVE - 2023	$ 4.5	$ 45.9	1/23-12/23	Replacement projects that (1) enhance system safety or reliability, or (2) reduce, or potentially reduce, greenhouse gas emissions.	January 2023
Columbia of Kentucky[6]	SMRP - 2023	$ 1.6	$ 41.6	1/23-12/23	Replacement of mains and inclusion of system safety investments.	January 2023
Columbia of Maryland	STRIDE - 2023	$ 1.3	$ 18.0	1/23-12/23	Pipeline upgrades designed to improve public safety or infrastructure reliability.	January 2023
NIPSCO - Electric[7]	TDSIC - 1	$ 10.4	$ 148.5	6/21-1/22	New or replacement projects undertaken for the purpose of safety, reliability, system modernization or economic development.	August 2022
NIPSCO - Electric	TDSIC - 2	$ 6.6	$ 143.5	2/22-7/22	New or replacement projects undertaken for the purpose of safety, reliability, system modernization or economic development.	February 2023

(1)Programs do not include any costs already included in base rates.
(2)The January through March 2021 investments included in these filings are also included in the pending Columbia of Ohio rate case. The infrastructure filings will be adjusted to reflect the final rate case outcome.
(3)NIPSCO Gas program incremental revenue decreased because of revisions for the rate case compliance filings amounts included in base rates.
(4)NIPSCO received approval for a new certificate of public convenience and necessity on December 28, 2022 for an additional Pipeline Safety III Compliance Plan, including $235.3M in capital and $34.1M in operation and maintenance expense project investments.
(5) Columbia of Virginia received a final order on November 1, 2022 modifying the SAVE filing incremental revenue and investments.
(6)Columbia of Kentucky received an Order on December 28, 2022, modifying its 2023 SMRP filing by removing recovery of the 2022 investment not recovered as part of the most recently approved rate case. This modification lowered incremental revenue recovered through SMRP to $1.6M, a reduction of $3.2M from the original filing.
(7)NIPSCO filed for a new electric TDSIC plan on June 1, 2021. An order approving NIPSCO's new electric TDSIC plan was received on December 28, 2021.

On March 30, 2022, NIPSCO Electric filed a petition with the IURC seeking approval of NIPSCO's federally mandated costs for closure of Michigan City Generating Station's CCR ash ponds. The project includes a total estimated $40.0 million of federally mandated retirement costs. A final order is expected in the first quarter of 2023. On November 2, 2022, NIPSCO Electric filed a petition with the IURC seeking approval of NIPSCO's federally mandated costs for closure of R.M. Schahfer Generation Station's multi-cell unit. The project includes a total estimated $53.0 million of federally mandated retirement costs. NIPSCO is requesting all associated accounting and ratemaking relief, including establishment of a periodic rate adjustment through the FMCA mechanism. On February 21, 2023, the Indiana Court of Appeals issued a decision in a case filed by an Indiana utility company interpreting a statute authorizing recovery of federally mandated costs, finding that such costs incurred prior to issuance of an order by the IURC are not recoverable as federally mandated costs. If any of NIPSCO's CCR costs were determined to be not eligible for recovery under the federal mandate mechanism, NIPSCO would seek recovery through depreciation within base rates. Refer to Note 19, "Other Commitments and Contingencies - E. Environmental Matters," in the Notes to Consolidated Financial Statements for further discussion of the CCRs.

Refer to Note 9, "Regulatory Matters," in the Notes to Consolidated Financial Statements for a further discussion of regulatory developments during 2022.

NISOURCE INC.

Financing Activities

Common Stock, Preferred Stock and Equity Unit Sale. Refer to Note 13, "Equity," in the Notes to Consolidated Financial Statements for information on common stock, preferred stock and equity units activity.

Short-term Debt. Refer to Note 16, "Short-Term Borrowings," in the Notes to Consolidated Financial Statements for information on short-term debt.

Long-term Debt. Refer to Note 15, "Long-Term Debt," in the Notes to Consolidated Financial Statements for information on long-term debt.

Non-controlling Interest. Refer to Note 4, "Variable Interest Entities," in the Notes to Consolidated Financial Statements for information on contributions from noncontrolling interest activity.

Sources of Liquidity

The following table displays our liquidity position as of December 31, 2022 and 2021:

Year Ended December 31, *(in millions)*	**2022**	2021
Current Liquidity		
Revolving Credit Facility	**$ 1,850.0**	$ 1,850.0
Accounts Receivable Programs[1]	**447.2**	251.2
Less:		
Commercial Paper	**415.0**	560.0
Accounts Receivable Programs Utilized	**347.2**	—
Letters of Credit Outstanding Under Credit Facility	**10.2**	18.9
Add:		
Cash and Cash Equivalents	**40.8**	84.2
Net Available Liquidity	**$ 1,565.6**	$ 1,606.5

[1]Represents the lesser of the seasonal limit or maximum borrowings supportable by the underlying receivables.

Debt Covenants. We are subject to a financial covenant under our revolving credit facility and term credit agreement, which requires us to maintain a debt to capitalization ratio that does not exceed 70%. As of December 31, 2022, the ratio was 58.9%.

Credit Ratings. The credit rating agencies periodically review our ratings, taking into account factors such as our capital structure and earnings profile. The following table includes our and NIPSCO's credit ratings and ratings outlook as of December 31, 2022. There have been no changes to our credit ratings or outlooks since February 2020.

A credit rating is not a recommendation to buy, sell or hold securities, and may be subject to revision or withdrawal at any time by the assigning rating organization.

	S&P		Moody's		Fitch	
	Rating	Outlook	Rating	Outlook	Rating	Outlook
NiSource	BBB+	Stable	Baa2	Stable	BBB	Stable
NIPSCO	BBB+	Stable	Baa1	Stable	BBB	Stable
Commercial Paper	A-2	Stable	P-2	Stable	F2	Stable

Certain of our subsidiaries have agreements that contain "ratings triggers" that require increased collateral if our credit ratings or the credit ratings of certain of our subsidiaries are below investment grade. These agreements are primarily for insurance purposes and for the physical purchase or sale of power. As of December 31, 2022, a collateral requirement of approximately $85.7 million would be required in the event of a downgrade below investment grade. In addition to agreements with ratings triggers, there are other agreements that contain "adequate assurance" or "material adverse change" provisions that could necessitate additional credit support such as letters of credit and cash collateral to transact business.

Equity. Our authorized capital stock consists of 620,000,000 shares, $0.01 par value, of which 600,000,000 are common stock and 20,000,000 are preferred stock. As of December 31, 2022, 412,142,602 shares of common stock and 1,302,500 shares of preferred stock were outstanding. For more information regarding our common and preferred stock, see Note 13, "Equity," in the Notes to Consolidated Financial Statements.

NISOURCE INC.

Contractual Obligations, Cash Requirements and Off-Balance Sheet Arrangements
We have certain contractual obligations requiring payments at specified periods. Our material cash requirements are detailed below. We intend to use funds from the liquidity sources referenced above to meet these cash requirements.

At December 31, 2022, we had $1,761.9 million in short-term borrowings outstanding. Refer to Note 15, "Long-Term Debt," and Note 16, "Short-Term Borrowings," in the Notes to Consolidated Financial Statements for further information on long-term debt and short-term borrowings, respectively.

During 2023 and 2024, we expect to make cash payments of $642.2 million and $556.9 million, respectively, related to pipeline service obligations including demand for gas transportation, gas storage and gas purchases.

Our expected payments include employer contributions to pension and other postretirement benefits plans expected to be made in 2023. Plan contributions beyond 2023 are dependent upon a number of factors, including actual returns on plan assets, which cannot be reliably estimated at this time. In 2023, we expect to make contributions of approximately $2.6 million to our pension plans and approximately $23.7 million to our postretirement medical and life plans. Refer to Note 12, "Pension and Other Postemployment Benefits," in the Notes to Consolidated Financial Statements for more information.

We cannot reasonably estimate the settlement amounts or timing of cash flows related to certain of our long-term obligations classified as "Total Other Liabilities" on the Consolidated Balance Sheets.

We have uncertain income tax positions for which we are unable to predict when the matters will be resolved. Refer to Note 11, "Income Taxes," in the Notes to Consolidated Financial Statements for more information.

NIPSCO has executed several PPAs to purchase 100% of the output from renewable generation facilities at a fixed price per MWh. NIPSCO has also executed several BTAs with developers to construct renewable generation facilities. See Note 19, "Other Commitments and Contingencies - A. Contractual Obligations," and Note 19, "Other Commitments and Contingencies," - F. "Other Matters - Generation Transition," in the Notes to Consolidated Financial Statements for additional information.

In addition, we, along with certain of our subsidiaries, enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include guarantees and stand-by letters of credit.

Refer to Note 19, "Other Commitments and Contingencies," in the Notes to Consolidated Financial Statements for additional information regarding our contractual obligations over the next 5 years and thereafter and our off-balance sheet arrangements.

Market Risk Disclosures

Risk is an inherent part of our businesses. The extent to which we properly and effectively identify, assess, monitor and manage each of the various types of risk involved in our businesses is critical to our profitability. We seek to identify, assess, monitor and manage, in accordance with defined policies and procedures, the following principal market risks that are involved in our businesses: commodity price risk, interest rate risk and credit risk. We manage risk through a multi-faceted process with oversight by the Risk Management Committee that requires constant communication, judgment and knowledge of specialized products and markets. Our senior management takes an active role in the risk management process and has developed policies and procedures that require specific administrative and business functions to assist in the identification, assessment and control of various risks. These may include, but are not limited to market, operational, financial, compliance and strategic risk types. In recognition of the increasingly varied and complex nature of the energy business, our risk management process, policies and procedures continue to evolve and are subject to ongoing review and modification.

Commodity Price Risk
Our Gas and Electric Operations have commodity price risk primarily related to the purchases of natural gas and power. To manage this market risk, our subsidiaries use derivatives, including commodity futures contracts, swaps, forwards and options. We do not participate in speculative energy trading activity.

Commodity price risk resulting from derivative activities at our rate-regulated subsidiaries is limited and does not bear signification exposure to earnings risk, since our current regulatory mechanisms allow recovery of prudently incurred purchased power, fuel and gas costs through the rate-making process, including gains or losses on these derivative instruments. These changes are included in the GCA and FAC regulatory rate-recovery mechanisms. If these mechanisms were to be adjusted or eliminated, these subsidiaries may begin providing services without the benefit of the traditional rate-making process and may be more exposed to commodity price risk. For additional information, see "Results and Discussion of Segment Operations" in this Management's Discussion.

Our subsidiaries are required to make cash margin deposits with their brokers to cover actual and potential losses in the value of outstanding exchange traded derivative contracts. The amount of these deposits, some of which is reflected in our restricted cash balance, may fluctuate significantly during periods of high volatility in the energy commodity markets.

Refer to Note 10, "Risk Management Activities," in the Notes to Consolidated Financial Statements for further information on our commodity price risk assets and liabilities as of December 31, 2022 and 2021.

Interest Rate Risk

We are exposed to interest rate risk as a result of changes in interest rates on borrowings under our revolving credit agreement, commercial paper program, term credit agreement and accounts receivable programs, which have interest rates that are indexed to short-term market interest rates. Based upon average borrowings and debt obligations subject to fluctuations in short-term market interest rates, an increase (or decrease) in short-term interest rates of 100 basis points (1%) would have increased (or decreased) interest expense by $8.7 million and $3.1 million for 2022 and 2021, respectively. We are also exposed to interest rate risk as a result of changes in benchmark rates that can influence the interest rates of future debt issuances. From time to time we may enter into forward interest rate instruments to lock in long term interest costs and/ or rates.

Refer to Note 10, "Risk Management Activities," in the Notes to Consolidated Financial Statements for further information on our interest rate risk assets and liabilities as of December 31, 2022 and 2021.

Credit Risk

Due to the nature of the industry, credit risk is embedded in many of our business activities. Our extension of credit is governed by a Corporate Credit Risk Policy. In addition, our Risk Management Committee has put guidelines in place which document management approval levels for credit limits, evaluation of creditworthiness, and credit risk mitigation efforts. Exposures to credit risks are monitored by the risk management function, which is independent of commercial operations. Credit risk arises due to the possibility that a customer, supplier or counterparty will not be able or willing to fulfill its obligations on a transaction on or before the settlement date. For derivative-related contracts, credit risk arises when counterparties are obligated to deliver or purchase defined commodity units of gas or power to us at a future date per execution of contractual terms and conditions. Exposure to credit risk is measured in terms of both current obligations and the market value of forward positions net of any posted collateral such as cash and letters of credit.

We evaluate the financial status of our banking partners through the use of market-based metrics such as credit default swap pricing levels, and also through traditional credit ratings provided by major credit rating agencies.

Other Information

Critical Accounting Estimates

We apply certain accounting policies in accordance with GAAP, which require that we make estimates and judgments that have had, and may continue to have, significant impacts on our operations and Consolidated Financial Statements. We evaluate our estimates on an ongoing basis. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates. We believe the following represent the more significant items requiring the use of judgment in preparing our Consolidated Financial Statements:

Basis of Accounting for Rate-Regulated Subsidiaries. ASC Topic 980, *Regulated Operations*, provides that rate-regulated subsidiaries account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred on the Consolidated Balance Sheets and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. The total amounts of regulatory assets and liabilities reflected on the Consolidated Balance Sheets were $2,580.8 million and $2,012.6 million at December 31, 2022, and $2,492.2 million and $1,980.0 million at December 31, 2021, respectively. For additional information, refer to Note 9, "Regulatory Matters," in the Notes to Consolidated Financial Statements.

In the event that regulation significantly changes the opportunity for us to recover our costs in the future, all or a portion of our regulated operations may no longer meet the criteria for the application of ASC Topic 980, *Regulated Operations*. In such event, a write-down of all or a portion of our existing regulatory assets and liabilities could result. If transition cost recovery is approved by the appropriate regulatory bodies that would meet the requirements under GAAP for continued accounting as

NISOURCE INC.

regulatory assets and liabilities during such recovery period, the regulatory assets and liabilities would be reported at the recoverable amounts. If we were unable to continue to apply the provisions of ASC Topic 980, *Regulated Operations*, we would be required to apply the provisions of ASC Topic 980-20, *Discontinuation of Rate-Regulated Accounting*. In management's opinion, our regulated subsidiaries will be subject to ASC Topic 980, *Regulated Operations* for the foreseeable future.

Certain of the regulatory assets reflected on our Consolidated Balance Sheets require specific regulatory action in order to be included in future service rates. Although recovery of these amounts is not guaranteed, we believe that these costs meet the requirements for deferral as regulatory assets. If we determine that the amounts included as regulatory assets are no longer probable of recovery, a charge to income would immediately be required to the extent of the unrecoverable amounts.

One of the more significant items recorded through the application of this accounting guidance is the regulatory overlay for JV accounting. The application of HLBV to consolidated VIEs generally results in the recognition of profit from the related JVs over a time frame that is different from when the regulatory return is earned. In accordance with the principles of ASC 980, we have recognized a regulatory deferral of certain amounts representing the timing difference between the profit earned from the JVs and the amount included in regulated rates to recover our approved investments in consolidated JVs. For additional information, refer to Note 1, "Nature of Operations and Summary of Significant Accounting Policies - S. VIEs and Allocation of Earnings," in the Notes to Consolidated Financial Statements.

Equity Unit Transaction. We record the Series C Mandatory Convertible Preferred Stock and forward purchase contracts that comprise the Corporate Units as a single unit of account and classify the Corporate Units as equity under the provisions of ASC 480 and ASC 815. Significant judgments regarding the economic linkage between the Series C Mandatory Convertible Preferred Stock and the forward purchase contracts, as well as the substance of the terms and conditions of the Corporate Units, were required by management in making these determinations.

The initial classification of the Corporate Units, whether viewed as a single unit of account or as two freestanding financial instruments, would affect our financial results. If determined to be two units of account, the forward purchase contracts underlying the Corporate Units would be classified as a derivative and result in impacts to net income through the recognition of interest expense and mark-to-market adjustments. If determined to be one unit of account, the equity classification of the Corporate Units would have no material impact on net income. Each classification has differing impacts to the numerator in the computation of EPS.

We consider that there are a small number of similar equity hosted unit structures and that our unit structure is unique. We also consider that the provisions of ASC 480 and ASC 815 that govern the determination of unit of account are highly complex and that alternate conclusions reached under this guidance would result in materially different financial results. See Note 13, "Equity," in the Notes to Consolidated Financial Statements for additional details of the equity unit transaction.

Pension and Postretirement Benefits. We have defined benefit plans for both pension and other postretirement benefits. The calculation of the net obligations and annual expense related to the plans requires a significant degree of judgment regarding the discount rates to be used in bringing the liabilities to present value, expected long-term rates of return on plan assets, health care trend rates, and mortality rates, among other assumptions. Due to the size of the plans and the long-term nature of the associated liabilities, changes in the assumptions used in the actuarial estimates could have material impacts on the measurement of the net obligations and annual expense recognition. Differences between actuarial assumptions and actual plan results are deferred into AOCI or a regulatory balance sheet account, depending on the jurisdiction of our entity. These deferred gains or losses are then amortized into the income statement when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the fair value of plan assets (known in GAAP as the "corridor" method) or when settlement accounting is triggered.

The discount rates, expected long-term rates of return on plan assets, health care cost trend rates and mortality rates are critical assumptions. Methods used to develop these assumptions are described below. While a third party actuarial firm assists with the development of many of these assumptions, we are ultimately responsible for selecting the final assumptions.

The discount rate is utilized principally in calculating the actuarial present value of pension and other postretirement benefit obligations and net periodic pension and other postretirement benefit plan costs. Our discount rates for both pension and other postretirement benefits are determined using spot rates along an AA-rated above median yield curve with cash flows matching the expected duration of benefit payments to be made to plan participants.

The expected long-term rate of return on plan assets is a component utilized in calculating annual pension and other postretirement benefit plan costs. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, target asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rate of return on assets. For measurement of 2022 net periodic benefit cost, we selected a weighted-average assumption of the expected pre-tax long-term rate of return of 4.80% and 5.72% for our pension and other postretirement benefit plan assets, respectively. For measurement of 2023 net periodic benefit cost, we selected a weighted-average assumption of the expected pre-tax long-term rate of return of 7.00% and 6.69% for our pension and other postretirement benefit plan assets, respectively.

We estimate the assumed health care cost trend rate, which is used in determining our other postretirement benefit net expense, based upon our actual health care cost experience, the effects of recently enacted legislation, third-party actuarial surveys and general economic conditions.

We utilize a full yield curve approach to estimate the service and interest components of net periodic benefit cost for pension and other postretirement benefits by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to the relevant projected cash flows. For further discussion of our pension and other postretirement benefits, see Note 12, "Pension and Other Postemployment Benefits," in the Notes to Consolidated Financial Statements.

Typically, we use the Society of Actuaries' most recently published mortality data in developing a best estimate of mortality as part of the calculation of the pension and other postretirement benefit obligations. We adopted Aon's U.S. Endemic Mortality Improvement scale MP-2021, accounting for both the near-term and long-term COVID-19 impacts.

The following tables illustrate the effects of changes in these actuarial assumptions while holding all other assumptions constant:

	Impact on December 31, 2022 Projected Benefit Obligation Increase/(Decrease)	
Change in Assumptions *(in millions)*	Pension Benefits	Other Postretirement Benefits
+50 basis points change in discount rate	$ (52.6)	$ (19.2)
-50 basis points change in discount rate	56.7	20.8

	Impact on 2022 Expense Increase/(Decrease)[1]	
Change in Assumptions *(in millions)*	Pension Benefits	Other Postretirement Benefits
+50 basis points change in discount rate	$ (1.7)	$ 0.5
-50 basis points change in discount rate	1.9	0.8
+50 basis points change in expected long-term rate of return on plan assets	(9.2)	(1.5)
-50 basis points change in expected long-term rate of return on plan assets	9.2	1.5

[1]Before labor capitalization and regulatory deferrals.

Goodwill and Other Intangible Assets. We have six goodwill reporting units, comprised of the six state operating companies within the Gas Distribution Operations reportable segment. Our goodwill assets at December 31, 2022 were $1,486 million, most of which resulted from the acquisition of Columbia on November 1, 2000.

As required by GAAP, we test for impairment of goodwill on an annual basis and on an interim basis when events or circumstances indicate that a potential impairment may exist. Our annual goodwill test takes place in the second quarter of each year and was performed on May 1, 2022. A qualitative ("step 0") test was completed on May 1, 2022 for all reporting units. In the Step 0 analysis, we assessed various assumptions, events and circumstances that would have affected the estimated fair value of the applicable reporting units as compared to the baseline "step 1" fair value measurement performed May 1, 2020. The results of this assessment indicated that it was more likely than not that the estimated fair value of the reporting units substantially exceeded the related carrying values of our reporting units; therefore, no "step 1" analysis was required and no impairment charges were indicated. Since the annual evaluation, there have been no indications that the fair values of the goodwill reporting units have decreased below the carrying values.

As noted above, application of the qualitative goodwill impairment test requires evaluating various events and circumstances to determine whether it is not more likely than not that the fair value of a reporting unit is less than its carrying amount. Although we believe all relevant factors were considered in the qualitative impairment analysis to reach the conclusion that goodwill is not impaired, significant changes in any one of the assumptions could potentially result in the recording of an impairment that could have significant impacts on the Consolidated Financial Statements.

See Note 7, "Goodwill," in the Notes to Consolidated Financial Statements for further information.

Unbilled Revenue. We record utility operating revenues when energy is delivered to our customers. However, the determination of energy sales to individual customers is based upon the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of their last meter reading are estimated and corresponding unbilled revenues are calculated. This unbilled revenue is estimated each month based upon historical usage, customer rates and weather. As of December 31, 2022 we recorded $453.0 million of customer accounts receivable for unbilled revenue. Significant fluctuations in energy demand for the unbilled period or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. Refer to Note 3, "Revenue Recognition," in the Notes to Consolidated Financial Statements for additional information regarding our significant judgments and estimates related to unbilled revenue recognition.

Income Taxes. The consolidated income tax provision and deferred income tax assets and liabilities, as well as any unrecognized tax benefits and valuation allowances, require use of estimates and significant management judgement. Although we believe that current estimates for deferred tax assets and liabilities are reasonable, actual results could differ from these estimates for a variety of reasons, including reasonable projections of taxable income, the ability and intent to implement tax planning strategies if necessary, and interpretations of applicable tax laws and regulations across multiple taxing jurisdictions. Ultimate resolution or clarification of income tax matters may result in favorable or unfavorable impacts to net income and cash flows, and adjustments to tax-related assets and liabilities could be material.

We account for uncertain income tax positions using a benefit recognition model with a two-step approach including a more-likely-than-not recognition threshold and a measurement approach based on the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. We evaluate each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant judgment is required to determine whether the recognition threshold has been met and, if so, the appropriate amount of tax benefits to be recorded in the consolidated financial statements. At December 31, 2022 we had $21.7 million of unrecognized tax benefits. Changes in these unrecognized tax benefits may result from remeasurement of amounts expected to be realized, settlements with tax authorities and expiration of statutes of limitations.

Valuation allowances against deferred tax assets are recorded when we conclude it is more likely than not such asset will not be realized in future periods. Accounting for income taxes also requires that only tax benefits for positions taken or expected to be taken on tax returns that meet the more-likely-than-not recognition threshold can be recognized or continue to be recognized. We evaluate each position solely on the technical merits and facts and circumstances of the position, assuming that the position will be examined by a taxing authority that has full knowledge of all relevant information. Significant judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized. At December 31, 2022, we had established $7.8 million of valuation allowances related to certain state NOL carryforwards. Refer to Note 11, "Income Taxes," in the Notes to Consolidated Financial Statements for additional information.

Recently Issued Accounting Pronouncements

Refer to Note 2, "Recent Accounting Pronouncements," in the Notes to Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Quantitative and Qualitative Disclosures about Market Risk are reported in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Risk Disclosures."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

NISOURCE INC.

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NISOURCE INC.
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of NiSource Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of NiSource Inc. and subsidiaries (the "Company") as of December 31, 2022 and 2021, the related statements of consolidated income (loss), comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2022, and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 22, 2023, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Impact of Rate Regulation on the Financial Statements - Refer to Notes 1 and 9 to the consolidated financial statements

Critical Audit Matter Description

The Company’s subsidiaries are fully regulated natural gas and electric utility companies serving customers in six states. These rate-regulated subsidiaries account for and report assets and liabilities consistent with the economic effect of the manner in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be charged to and collected from customers. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred on the consolidated balance sheets and are later recognized in income as the related amounts are included in customer rates and recovered from or refunded to customers.

The Company’s subsidiaries’ rates are subject to regulatory rate-setting processes. Rates are determined and approved in regulatory proceedings based on an analysis of the subsidiaries’ costs to provide utility service and a return on, and recovery of, the subsidiaries’ investment in the utility business. Regulatory decisions can have an impact on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered by rates. The respective commission’s regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested

NISOURCE INC.
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

capital. Decisions to be made by the commission in the future will impact the accounting for regulated operations, including decisions about the amount of allowable costs and return on invested capital included in rates and any refunds that may be required. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the commission will not approve: (1) full recovery of the costs of providing utility service, or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment.

We identified the accounting for rate-regulated subsidiaries as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs and (2) refunds of amounts previously collected from customers. Given that management’s accounting judgments are based on assumptions about the outcome of future decisions by regulatory commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate making process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the commissions focused on the ongoing Columbia Gas of Ohio base rate case and the Northern Indiana Public Service Company electric base rate case proceedings and included the following, among others:

- We tested the effectiveness of management’s controls over the evaluation of the likelihood of (1) the recovery in future rates of costs incurred as property, plant, and equipment and deferred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management’s controls over the initial recognition of amounts as property, plant, and equipment; regulatory assets or liabilities; and the monitoring and evaluation of regulatory developments, that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We evaluated the Company’s disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the commissions for the Company, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the commissions’ treatment of similar costs under similar circumstances. We evaluated the external information and compared to management’s recorded regulatory asset and liability balances for completeness.
- For regulatory matters in process, we inspected the Company’s and intervenors’ filings with the commissions that may impact the Company’s future rates, for any evidence that might contradict management’s assertions related to recoverability of recorded assets. Additionally, we evaluated the joint stipulation filed by Columbia Gas of Ohio with the Public Utilities Commission of Ohio.
- We inquired of management about property, plant, and equipment that may be abandoned with an emphasis on the generation strategy related to Northern Indiana Public Service Company’s R.M. Schahfer and Michigan City Generating Stations. We inspected minutes of the board of directors and regulatory orders and other filings with the commissions to identify evidence that may contradict management’s assertion regarding probability of an abandonment.
- We read the relevant regulatory orders issued by the Commission for the Company’s renewable energy investments. We evaluated the appropriateness of recognizing a regulatory liability or asset representing timing differences between the profit allocated under the Hypothetical Liquidation at Book Value (HLBV) method related to the consolidated joint ventures and the allowed earnings included in regulatory rates. We also evaluated the appropriateness of the offset to the regulatory liability or asset recorded in depreciation expense.
- We evaluated the Company’s disclosures related to the application of ASC Topic 980 to consolidated joint venture accounting.

/s/ DELOITTE & TOUCHE LLP
Columbus, Ohio
February 22, 2023

We have served as the Company's auditor since 2002.

NISOURCE INC.
STATEMENTS OF CONSOLIDATED INCOME (LOSS)

Year Ended December 31, *(in millions, except per share amounts)*	**2022**	2021	2020
Operating Revenues			
Customer revenues	**$ 5,738.6**	$ 4,731.3	$ 4,473.2
Other revenues	**112.0**	168.3	208.5
Total Operating Revenues	**5,850.6**	4,899.6	4,681.7
Operating Expenses			
Cost of energy	**2,110.5**	1,392.3	1,109.3
Operation and maintenance	**1,489.4**	1,456.0	1,585.9
Depreciation and amortization	**820.8**	748.4	725.9
Loss (gain) on sale of assets, net	**(104.2)**	7.7	410.6
Other taxes	**268.3**	288.3	299.2
Total Operating Expenses	**4,584.8**	3,892.7	4,130.9
Operating Income	**1,265.8**	1,006.9	550.8
Other Income (Deductions)			
Interest expense, net	**(361.6)**	(341.1)	(370.7)
Other, net	**52.2**	40.8	32.1
Loss on early extinguishment of long-term debt	**—**	—	(243.5)
Total Other Deductions, Net	**(309.4)**	(300.3)	(582.1)
Income (Loss) before Income Taxes	**956.4**	706.6	(31.3)
Income Taxes	**164.6**	117.8	(17.1)
Net Income (Loss)	**791.8**	588.8	(14.2)
Net income (loss) attributable to noncontrolling interest	**(12.3)**	3.9	3.4
Net Income (Loss) attributable to NiSource	**804.1**	584.9	(17.6)
Preferred dividends	**(55.1)**	(55.1)	(55.1)
Net Income (Loss) Available to Common Shareholders	**749.0**	529.8	(72.7)
Earnings (Loss) Per Share			
Basic Earnings (Loss) Per Share	**$ 1.84**	$ 1.35	$ (0.19)
Diluted Earnings (Loss) Per Share	**$ 1.70**	$ 1.27	$ (0.19)
Basic Average Common Shares Outstanding	**407.1**	393.6	384.3
Diluted Average Common Shares	**442.7**	417.3	384.3

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME (LOSS)

Year Ended December 31, *(in millions, net of taxes)*		**2022**		2021		2020
Net Income (Loss)	**$**	**791.8**	$	588.8	$	(14.2)
Other comprehensive income (loss):						
Net unrealized gain (loss) on available-for-sale securities[1]		**(13.3)**		(3.9)		2.7
Net unrealized gain (loss) on cash flow hedges[2]		**109.9**		25.4		(70.7)
Unrecognized pension and OPEB benefit (costs)[3]		**(6.9)**		8.4		3.9
Total other comprehensive income (loss)		**89.7**		29.9		(64.1)
Total Comprehensive Income (Loss)	**$**	**881.5**	$	618.7	$	(78.3)

(1) Net unrealized gain (loss) on available-for-sale securities, net of $3.5 million tax benefit, $1.0 million tax benefit and $0.7 million tax expense in 2022, 2021 and 2020, respectively.
(2) Net unrealized gain (loss) on derivatives qualifying as cash flow hedges, net of $36.4 million tax expense, $8.4 million tax expense and $23.4 million tax benefit in 2022, 2021 and 2020, respectively.
(3) Unrecognized pension and OPEB benefit (costs), net of $2.3 million tax benefit, $3.8 million tax expense and $0.1 million tax benefit in 2022, 2021 and 2020, respectively.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NiSource Inc.
CONSOLIDATED BALANCE SHEETS

(in millions)		**December 31, 2022**		December 31, 2021
ASSETS				
Property, Plant and Equipment				
Plant	**$**	**27,551.3**	$	25,171.3
Accumulated depreciation and amortization		**(7,708.7)**		(7,289.5)
Net Property, Plant and Equipment[(1)]		**19,842.6**		17,881.8
Investments and Other Assets				
Unconsolidated affiliates		**1.6**		0.8
Available-for-sale debt securities (amortized cost of $166.7 and $169.3, allowance for credit losses of $0.9 and $0.2, respectively)		**151.6**		171.8
Other investments		**71.0**		87.1
Total Investments and Other Assets		**224.2**		259.7
Current Assets				
Cash and cash equivalents		**40.8**		84.2
Restricted cash		**34.6**		10.7
Accounts receivable		**1,065.8**		849.1
Allowance for credit losses		**(23.9)**		(23.5)
Accounts receivable, net		**1,041.9**		825.6
Gas inventory		**531.7**		327.4
Materials and supplies, at average cost		**151.4**		139.1
Electric production fuel, at average cost		**68.8**		32.2
Exchange gas receivable		**128.1**		99.6
Regulatory assets		**233.2**		206.2
Deposits to renewable generation asset developer		**143.8**		—
Prepayments and other		**210.0**		195.8
Total Current Assets[(1)]		**2,584.3**		1,920.8
Other Assets				
Regulatory assets		**2,347.6**		2,286.0
Goodwill		**1,485.9**		1,485.9
Deferred charges and other		**252.0**		322.7
Total Other Assets		**4,085.5**		4,094.6
Total Assets	**$**	**26,736.6**	$	24,156.9

[(1)]Includes $978.5 million and $695.9 million in 2022 and 2021, respectively, of net property, plant and equipment assets and $25.7 million and $14.3 million in 2022 and 2021, respectively, of current assets of consolidated VIEs that may be used only to settle obligations of the consolidated VIEs. Refer to Note 4, "Variable Interest Entities," for additional information.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

NISOURCE INC.
CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)		**December 31, 2022**		December 31, 2021
CAPITALIZATION AND LIABILITIES				
Capitalization				
Stockholders' Equity				
Common stock - $0.01 par value, 600,000,000 shares authorized; 412,142,602 and 405,303,023 shares outstanding, respectively	**$**	**4.2**	$	4.1
Preferred stock - $0.01 par value, 20,000,000 shares authorized; 1,302,500 and 1,302,500 shares outstanding, respectively		**1,546.5**		1,546.5
Treasury stock		**(99.9)**		(99.9)
Additional paid-in capital		**7,375.3**		7,204.3
Retained deficit		**(1,213.6)**		(1,580.9)
Accumulated other comprehensive loss		**(37.1)**		(126.8)
Total NiSource Stockholders' Equity		**7,575.4**		6,947.3
Noncontrolling interest in consolidated subsidiaries		**326.4**		325.6
Total Stockholders' Equity		**7,901.8**		7,272.9
Long-term debt, excluding amounts due within one year		**9,523.6**		9,183.4
Total Capitalization		**17,425.4**		16,456.3
Current Liabilities				
Current portion of long-term debt		**30.0**		58.1
Short-term borrowings		**1,761.9**		560.0
Accounts payable		**899.5**		697.8
Customer deposits and credits		**324.7**		237.9
Taxes accrued		**246.2**		277.1
Interest accrued		**138.4**		105.5
Exchange gas payable		**147.6**		107.7
Regulatory liabilities		**236.8**		137.4
Accrued compensation and employee benefits		**167.5**		182.7
Obligations to renewable generation asset developer		**347.2**		—
Other accruals		**360.7**		382.0
Total Current Liabilities[(1)]		**4,660.5**		2,746.2
Other Liabilities				
Deferred income taxes		**1,854.5**		1,659.4
Accrued liability for postretirement and postemployment benefits		**245.5**		292.5
Regulatory liabilities		**1,775.8**		1,842.6
Asset retirement obligations		**478.1**		469.7
Other noncurrent liabilities and deferred credits		**296.8**		690.2
Total Other Liabilities[(1)]		**4,650.7**		4,954.4
Commitments and Contingencies (Refer to Note 19, "Other Commitments and Contingencies")				
Total Capitalization and Liabilities	**$**	**26,736.6**	$	24,156.9

[(1)]Includes $128.2 million and $10.0 million in 2022 and 2021, respectively, of current liabilities and $30.6 million and $20.5 million in 2022 and 2021, respectively, of other liabilities of consolidated VIEs that creditors do not have recourse to our general credit. Refer to Note 4, "Variable Interest Entities," for additional information.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
STATEMENTS OF CONSOLIDATED CASH FLOWS

Year Ended December 31, *(in millions)*	**2022**	2021	2020
Operating Activities			
Net Income (Loss)	$ **791.8**	$ 588.8	$ (14.2)
Adjustments to Reconcile Net Income to Net Cash from Operating Activities:			
Loss on early extinguishment of debt	**—**	—	243.5
Depreciation and amortization	**820.8**	748.4	725.9
Deferred income taxes and investment tax credits	**156.9**	111.9	(29.0)
Stock compensation expense and 401(k) profit sharing contribution	**24.9**	24.3	17.4
Loss (gain) on sale of assets	**(105.3)**	5.6	409.8
Other adjustments	**5.7**	(0.7)	(0.3)
Changes in Assets and Liabilities:			
Accounts receivable	**(216.3)**	(40.3)	(3.9)
Inventories	**(258.9)**	(112.9)	(1.5)
Accounts payable	**165.0**	54.9	(29.7)
Exchange gas receivable/payable	**57.8**	(114.2)	(6.9)
Other accruals	**73.4**	43.0	(175.1)
Prepayments and other current assets	**(9.8)**	(36.6)	(5.9)
Regulatory assets/liabilities	**(129.4)**	76.8	70.8
Postretirement and postemployment benefits	**84.7**	(96.4)	(103.6)
Deferred charges and other noncurrent assets	**(4.1)**	(4.7)	(15.0)
Other noncurrent liabilities and deferred credits	**(47.8)**	(30.0)	21.7
Net Cash Flows from Operating Activities	**1,409.4**	1,217.9	1,104.0
Investing Activities			
Capital expenditures	**(2,203.1)**	(1,838.0)	(1,758.1)
Insurance Recoveries	**105.0**	—	—
Cost of removal	**(151.7)**	(121.1)	(138.2)
Proceeds from disposition of assets	**—**	0.7	1,115.9
Purchases of available-for-sale securities	**(73.5)**	(102.9)	(144.7)
Sales of available-for-sale securities	**75.7**	97.8	131.4
Payment to renewable generation asset developer	**(323.9)**	(240.4)	(85.3)
Other investing activities	**1.3**	(1.0)	(0.1)
Net Cash Flows used for Investing Activities	**(2,570.2)**	(2,204.9)	(879.1)
Financing Activities			
Proceeds from issuance of long-term debt	**345.6**	—	2,974.0
Repayments of long-term debt and finance lease obligations	**(60.3)**	(25.7)	(1,622.0)
Issuance of short-term debt (maturity > 90 days)	**1,000.0**	—	1,350.0
Repayment of short-term debt (maturity > 90 days)	**—**	—	(2,200.0)
Change in short-term debt (maturity ≤ 90 days)	**202.2**	57.0	(420.1)
Issuance of common stock, net of issuance costs	**154.3**	299.6	211.4
Equity costs, premiums and other debt related costs	**(13.0)**	(18.2)	(246.5)
Contributions from noncontrolling interest	**21.2**	245.1	82.2
Distributions to noncontrolling interest	**(6.0)**	(0.6)	—
Issuance of equity units, net of underwriting costs	**—**	839.9	—
Dividends paid - common stock	**(381.5)**	(345.2)	(321.6)
Dividends paid - preferred stock	**(55.1)**	(55.1)	(55.1)
Contract liability payment	**(66.1)**	(40.5)	—
Net Cash Flows from (used for) Financing Activities	**1,141.3**	956.3	(247.7)
Change in cash, cash equivalents and restricted cash	**(19.5)**	**(30.7)**	**(22.8)**
Cash, cash equivalents and restricted cash at beginning of period	**94.9**	125.6	148.4
Cash, Cash Equivalents and Restricted Cash at End of Period	$ **75.4**	$ 94.9	$ 125.6

Reconciliation to Balance Sheet	**2022**	2021	2020
Cash and cash equivalents	**40.8**	84.2	116.5
Restricted Cash	**34.6**	10.7	9.1
Total Cash, Cash Equivalents and Restricted Cash	**75.4**	94.9	125.6

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
STATEMENTS OF CONSOLIDATED STOCKHOLDERS' EQUITY

(in millions)	Common Stock	Preferred Stock[(1)]	Treasury Stock	Additional Paid-In Capital	Retained Deficit	Accumulated Other Comprehensive Loss	Noncontrolling Interest in Consolidated Subsidiaries	Total
Balance as of January 1, 2020	**$ 3.8**	**$ 880.0**	**$ (99.9)**	**$ 6,666.2**	**$(1,370.8)**	**$ (92.6)**	**$ —**	**$ 5,986.7**
Comprehensive Loss:								
Net Income (Loss)	—	—	—	—	(17.6)	—	3.4	(14.2)
Other comprehensive loss, net of tax	—	—	—	—	—	(64.1)	—	(64.1)
Dividends:								
Common stock ($0.84 per share)	—	—	—	—	(321.7)	—	—	(321.7)
Preferred stock (See Note 13)	—	—	—	—	(55.1)	—	—	(55.1)
Contributions from noncontrolling interest	—	—	—	—	—	—	82.2	82.2
Stock issuances:								
Employee stock purchase plan	—	—	—	5.7	—	—	—	5.7
Long-term incentive plan	—	—	—	8.4	—	—	—	8.4
401(k) and profit sharing	—	—	—	13.4	—	—	—	13.4
ATM Program	0.1	—	—	196.4	—	—	—	196.5
Balance as of December 31, 2020	**$ 3.9**	**$ 880.0**	**$ (99.9)**	**$ 6,890.1**	**$(1,765.2)**	**$ (156.7)**	**$ 85.6**	**$ 5,837.8**
Comprehensive Income:								
Net Income	—	—	—	—	584.9	—	3.9	588.8
Other comprehensive income, net of tax	—	—	—	—	—	29.9	—	29.9
Dividends:								
Common stock ($0.88 per share)	—	—	—	—	(345.5)	—	—	(345.5)
Preferred stock (See Note 13)	—	—	—	—	(55.1)	—	—	(55.1)
Contributions from noncontrolling interest	—	—	—	—	—	—	236.7	236.7
Distributions to noncontrolling interest	—	—	—	—	—	—	(0.6)	(0.6)
Stock issuances:								
Equity Units	—	666.5	—	—	—	—	—	666.5
Employee stock purchase plan	—	—	—	5.0	—	—	—	5.0
Long-term incentive plan	—	—	—	11.8	—	—	—	11.8
401(k) and profit sharing	—	—	—	9.5	—	—	—	9.5
ATM Program	0.2	—	—	287.9	—	—	—	288.1
Balance as of December 31, 2021	**$ 4.1**	**$ 1,546.5**	**$ (99.9)**	**$ 7,204.3**	**$(1,580.9)**	**$ (126.8)**	**$ 325.6**	**$ 7,272.9**
Comprehensive Income:								
Net Income (Loss)	—	—	—	—	804.1	—	(12.3)	791.8
Other comprehensive income, net of tax	—	—	—	—	—	89.7	—	89.7
Dividends:								
Common stock ($0.94 per share)	—	—	—	—	(381.7)	—	—	(381.7)
Preferred stock (See Note 13)	—	—	—	—	(55.1)	—	—	(55.1)
Contributions from noncontrolling interest	—	—	—	—	—	—	19.1	19.1
Distributions to noncontrolling interest	—	—	—	—	—	—	(6.0)	(6.0)
Stock issuances:								
Employee stock purchase plan	—	—	—	5.2	—	—	—	5.2
Long-term incentive plan	—	—	—	14.3	—	—	—	14.3
401(k) and profit sharing	—	—	—	9.7	—	—	—	9.7
ATM Program	0.1	—	—	141.8	—	—	—	141.9
Balance as of December 31, 2022	**$ 4.2**	**$ 1,546.5**	**$ (99.9)**	**$ 7,375.3**	**$(1,213.6)**	**$ (37.1)**	**$ 326.4**	**$ 7,901.8**

[(1)]Series A, Series B, and Series C shares have an aggregate liquidation preference of $400M, $500M, and $863M, respectively. See Note 13, "Equity," for additional information.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NiSource Inc.
STATEMENTS OF CONSOLIDATED STOCKHOLDERS' EQUITY (continued)

	Preferred	Common		
(in thousands)	Shares	Shares	Treasury	Outstanding
Balance as of January 1, 2020	**440**	**386,099**	**(3,963)**	**382,136**
Issued:				
Employee stock purchase plan	—	236	—	236
Long-term incentive plan	—	385	—	385
401(k) and profit sharing plan	—	544	—	544
ATM Program	—	8,459	—	8,459
Balance as of December 31, 2020	**440**	**395,723**	**(3,963)**	**391,760**
Issued:				
Equity Units	863	—	—	—
Employee stock purchase plan	—	209	—	209
Long-term incentive plan	—	418	—	418
401(k) and profit sharing plan	—	391	—	391
ATM Program	—	12,525	—	12,525
Balance as of December 31, 2021	**1,303**	**409,266**	**(3,963)**	**405,303**
Issued:				
Employee stock purchase plan	—	186	—	186
Long-term incentive plan	—	375	—	375
401(k) and profit sharing plan	—	337	—	337
ATM Program	—	5,942	—	5,942
Balance as of December 31, 2022	**1,303**	**416,106**	**(3,963)**	**412,143**

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

1. Nature of Operations and Summary of Significant Accounting Policies

A. Company Structure and Principles of Consolidation. We are an energy holding company incorporated in Delaware and headquartered in Merrillville, Indiana. Our subsidiaries are fully regulated natural gas and electric utility companies serving approximately 3.7 million customers in six states. We generate substantially all of our operating income through these rate-regulated businesses. The consolidated financial statements include the accounts of us, our majority-owned subsidiaries, and VIEs of which we are the primary beneficiary after the elimination of all intercompany accounts and transactions.

B. Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

C. Cash, Cash Equivalents and Restricted Cash. We consider all highly liquid investments with original maturities of three months or less to be cash equivalents. We report amounts deposited in brokerage accounts for margin requirements as restricted cash. In addition, we have amounts deposited in trusts to satisfy requirements for the provision of various property, liability, workers compensation, and long-term disability insurance, which is classified as restricted cash on the Consolidated Balance Sheets and disclosed with cash and cash equivalents on the Statements of Consolidated Cash Flows.

D. Accounts Receivable and Unbilled Revenue. Accounts receivable on the Consolidated Balance Sheets includes both billed and unbilled amounts. Unbilled amounts of accounts receivable relate to a portion of a customer's consumption of gas or electricity from the last cycle billing date through the last day of the month (balance sheet date). Factors taken into consideration when estimating unbilled revenue include historical usage, customer rates, weather and reasonable and supportable forecasts. Accounts receivable fluctuates from year to year depending in large part on weather impacts and price volatility. Our accounts receivable on the Consolidated Balance Sheets include unbilled revenue, less reserves. The reserve for uncollectible receivables is our best estimate of the amount of probable credit losses in the existing accounts receivable. We determined the reserve based on historical collection experience, current market conditions and reasonable and supportable forecasts. Account balances are charged against the allowance when it is anticipated the receivable will not be recovered. Refer to Note 3, "Revenue Recognition," for additional information on customer-related accounts receivable, including amounts related to unbilled revenues.

E. Investments in Debt Securities. Our investments in debt securities are carried at fair value and are designated as available-for-sale. These investments are included within "Available-for-sale debt securities" on the Consolidated Balance Sheets. Unrealized gains and losses, net of deferred income taxes, are recorded to accumulated other comprehensive income or loss. At each reporting period these investments are qualitatively and quantitatively assessed to determine whether a decline in fair value below the amortized cost basis has resulted from a credit loss or other factors. Impairments related to credit loss are recorded through an allowance for credit losses. Impairments that are not related to credit losses are included in other comprehensive income and are reflected in the Statements of Consolidated Income (Loss). No material impairment charges were recorded for the years ended December 31, 2022, 2021 or 2020. Refer to Note 18, "Fair Value," for additional information.

F. Basis of Accounting for Rate-Regulated Subsidiaries. Rate-regulated subsidiaries account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be charged and collected. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred on the Consolidated Balance Sheets and are later recognized in income as the related amounts are included in customer rates and recovered from or refunded to customers.

We continually evaluate whether or not our operations are within the scope of ASC 980 and rate regulations. As part of that analysis, we evaluate probability of recovery for our regulatory assets. In management's opinion, our regulated subsidiaries will be subject to regulatory accounting for the foreseeable future. Refer to Note 9, "Regulatory Matters," for additional information.

G. Plant and Other Property and Related Depreciation and Maintenance. Property, plant and equipment (principally utility plant) is stated at cost. Our rate-regulated subsidiaries record depreciation using composite rates on a straight-line basis over the remaining service lives of the electric, gas and common properties, as approved by the appropriate regulators.

Non-utility property includes renewable generation assets owned by JVs of which we are the primary beneficiary and is generally depreciated on a straight-line basis over the life of the associated assets. Refer to Note 6, "Property, Plant and Equipment," for additional information related to depreciation expense.

For rate-regulated companies where provided for in rates, AFUDC is capitalized on all classes of property except organization costs, land, autos, office equipment, tools and other general property purchases. The allowance is applied to construction costs for that period of time between the date of the expenditure and the date on which such project is placed in service. Our consolidated pre-tax rate for AFUDC was 3.4% in 2022, 3.3% in 2021 and 2.6% in 2020.

Generally, our subsidiaries follow the practice of charging maintenance and repairs, including the cost of removal of minor items of property, to expense as incurred. When our subsidiaries retire regulated property, plant and equipment, original cost plus the cost of retirement, less salvage value, is charged to accumulated depreciation. However, when it becomes probable a regulated asset will be retired substantially in advance of its original expected useful life or is abandoned, the cost of the asset and the corresponding accumulated depreciation is recognized as a separate asset. If the asset is still in operation, the gross amounts are classified as "Non-Utility and Other " as described in Note 6, "Property, Plant and Equipment." If the asset is no longer operating but still subject to recovery, the net amount is classified in "Regulatory assets" on the Consolidated Balance Sheets. If we are able to recover a full return of and on investment, the carrying value of the asset is based on historical cost. If we are not able to recover a full return on investment, a loss on impairment is recognized to the extent the net book value of the asset exceeds the present value of future revenues discounted at the incremental borrowing rate.

External and internal costs associated with on-premise computer software developed for internal use are capitalized. Capitalization of such costs commences upon the completion of the preliminary stage of each project. Once the installed software is ready for its intended use, such capitalized costs are amortized on a straight-line basis generally over a period of five years. External and internal up-front implementation costs associated with cloud computing arrangements that are service contracts are deferred on the Consolidated Balance Sheets. Once the installed software is ready for its intended use, such deferred costs are amortized on a straight-line basis to "Operation and maintenance," over the minimum term of the contract plus contractually-provided renewal periods that are reasonable, expected to be exercised.

H. Goodwill and Other Intangible Assets. Substantially all of our goodwill relates to the excess of cost over the fair value of the net assets acquired in the Columbia acquisition on November 1, 2000. We test our goodwill for impairment annually as of May 1, or more frequently if events and circumstances indicate that goodwill might be impaired. Fair value of our reporting units is determined using a combination of income and market approaches. See Note 7, "Goodwill," for additional information.

I. Accounts Receivable Transfer Programs. Certain of our subsidiaries have agreements with third parties to transfer certain accounts receivable without recourse. These transfers of accounts receivable are accounted for as secured borrowings. The entire gross receivables balance remains on the December 31, 2022 and 2021 Consolidated Balance Sheets. When amounts are securitized, the short-term debt is recorded in the amount of proceeds received from the transferees involved in the transactions. Refer to Note 16, "Short-Term Borrowings," for further information.

J. Gas Cost and Fuel Adjustment Clause. Our regulated subsidiaries defer most differences between gas and fuel purchase costs and the recovery of such costs in revenues and adjust future billings for such deferrals on a basis consistent with applicable state-approved tariff provisions. These deferred balances are recorded as "Regulatory assets" or "Regulatory liabilities," as appropriate, on the Consolidated Balance Sheets. Refer to Note 9, "Regulatory Matters," for additional information.

K. Inventory. Both the LIFO inventory methodology and the weighted average cost methodology are used to value natural gas in storage, as approved by regulators for all of our regulated subsidiaries. Inventory valued using LIFO was $43.0 million and $44.9 million at December 31, 2022 and 2021, respectively. Based on the average cost of gas using the LIFO method, the estimated replacement cost of gas in storage was greater than the stated LIFO cost by $7.7 million at December 31, 2022 and was less than the stated LIFO cost by $13.6 million at December 31, 2021. As all LIFO inventory costs are collected from customers through our rate-regulated subsidiaries, no inventory impairment has been recorded. Gas inventory valued using the weighted average cost methodology was $488.7 million at December 31, 2022 and $282.4 million at December 31, 2021.

Electric production fuel is valued using the weighted average cost inventory methodology, as approved by NIPSCO's regulator.

Materials and supplies are valued using the weighted average cost inventory methodology.

L. Accounting for Exchange and Balancing Arrangements of Natural Gas. Our Gas Distribution Operations segment enters into balancing and exchange arrangements of natural gas as part of its operations and off-system sales programs. We record a receivable or payable for any of our respective cumulative gas imbalances, as well as for any gas inventory borrowed or lent under a Gas Distribution Operations exchange agreement. Exchange gas is valued based on individual regulatory jurisdiction requirements (for example, historical spot rate, spot at the beginning of the month). These receivables and payables are recorded as “Exchange gas receivable” or “Exchange gas payable” on our Consolidated Balance Sheets, as appropriate.

M. Accounting for Risk Management Activities. We account for our derivatives and hedging activities in accordance with ASC 815. We recognize all derivatives as either assets or liabilities on the Consolidated Balance Sheets at fair value, unless such contracts are exempted as a normal purchase normal sale under the provisions of the standard. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation.

We do not offset the fair value amounts recognized for any of our derivative instruments against the fair value amounts recognized for the right to reclaim cash collateral or obligation to return cash collateral for derivative instruments executed with the same counterparty under a master netting arrangement. See Note 10, "Risk Management Activities," for additional information.

N. Income Taxes and Investment Tax Credits. We record income taxes to recognize full interperiod tax allocations. Under the asset and liability method, deferred income taxes are provided for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amount and the tax basis of existing assets and liabilities. Investment tax credits associated with regulated operations are deferred and amortized as a reduction to income tax expense over the estimated useful lives of the related properties.

To the extent certain deferred income taxes of the regulated companies are recoverable or payable through future rates, regulatory assets and liabilities have been established. Regulatory assets for income taxes are primarily attributable to property-related tax timing differences for which deferred taxes had not been provided in the past when regulators did not recognize such taxes as costs in the rate-making process. Regulatory liabilities for income taxes are primarily attributable to the regulated companies’ obligation to refund to ratepayers deferred income taxes provided at rates higher than the current Federal income tax rate. Such property-related amounts are credited to ratepayers using either the average rate assumption method or the reverse South Georgia method. Non property-related amounts are credited to ratepayers consistent with state utility commission direction.

Pursuant to the Internal Revenue Code and relevant state taxing authorities, we and our subsidiaries file consolidated income tax returns for federal and certain state jurisdictions. We and our subsidiaries are parties to a tax sharing agreement. Income taxes recorded by each party represent amounts that would be owed had the party been separately subject to tax.

O. Pension Remeasurement. We utilize a third-party actuary for the purpose of performing actuarial valuations of our defined benefit plans. Annually, as of December 31, we perform a remeasurement for our pension plans. Quarterly, we monitor for significant events, and if a significant event is identified, we perform a qualitative and quantitative assessment to determine if the resulting remeasurement would materially impact the NiSource financial statements. If material, an interim remeasurement is performed. We had one such interim remeasurement in the second quarter of 2022. See Note 12, "Pension and Other Postemployment Benefits," for additional information.

P. Environmental Expenditures. We accrue for costs associated with environmental remediation obligations, including expenditures related to asset retirement obligations and cost of removal, when the incurrence of such costs is probable and the amounts can be reasonably estimated, regardless of when the expenditures are actually made. The undiscounted estimated future expenditures are based on currently enacted laws and regulations, existing technology and estimated site-specific costs where assumptions may be made about the nature and extent of site contamination, the extent of cleanup efforts, costs of alternative cleanup methods and other variables. The liability is adjusted as further information is discovered or circumstances change. The accruals for estimated environmental expenditures are recorded on the Consolidated Balance Sheets in “Other accruals” for short-term portions of these liabilities and “Other noncurrent liabilities” for the respective long-term portions of these liabilities. Rate-regulated subsidiaries applying regulatory accounting establish regulatory assets on the Consolidated Balance Sheets to the extent that future recovery of environmental remediation costs is probable through the regulatory process. Refer to Note 8, "Asset Retirement Obligations," and Note 19, "Other Commitments and Contingencies," for further information.

Q. Excise Taxes. As an agent for some state and local governments, we invoice and collect certain excise taxes levied by state and local governments on customers and record these amounts as liabilities payable to the applicable taxing jurisdiction. Such balances are presented within "Other accruals" on the Consolidated Balance Sheets. These types of taxes collected from customers, comprised largely of sales taxes, are presented on a net basis affecting neither revenues nor cost of sales. We account for excise taxes for which we are liable by recording a liability for the expected tax with a corresponding charge to "Other taxes" expense on the Statements of Consolidated Income (Loss).

R. Accrued Insurance Liabilities. We accrue for insurance costs related to workers compensation, automobile, property, general and employment practices liabilities based on the most probable value of each claim. In general, claim values are determined by professional, licensed loss adjusters who consider the facts of the claim, anticipated indemnification and legal expenses, and respective state rules. Claims are reviewed by us at least quarterly and an adjustment is made to the accrual based on the most current information.

S. VIEs and Allocation of Earnings. We fund a significant portion of our renewable generation assets through JVs with tax equity partners. We consolidate these JVs in accordance with ASC 810 as they are VIEs in which we hold a variable interest, and we control decisions that are significant to the JVs' ongoing operations and economic results (i.e., we are the primary beneficiary).

These JVs are subject to profit sharing arrangements in which the allocation of the JVs' cash distributions and tax benefits to members is based on factors other than members' relative ownership percentages. As such, we utilize the HLBV method to allocate proceeds to each partner at the balance sheet date based on the liquidation provisions of the related JV's operating agreement and adjusts the amount of the VIE's net income attributable to us and the noncontrolling tax equity member during the period.

In each reporting period, the application of HLBV to our consolidated VIEs results in a difference between the amount of profit from the consolidated JVs and the amount included in regulated rates. As discussed above in "F. Basis of Accounting for Rate-Regulated Subsidiaries," we are subject to the accounting and reporting requirements of ASC 980. In accordance with these principles, we recognize a regulatory liability or asset for amounts representing the timing difference between the profit earned from the JVs and the amount included in regulated rates to recover our approved investments in consolidated JVs. The amounts recorded in income will ultimately reflect the amount allowed in regulated rates to recover our investments over the useful life of the projects. The offset to the regulatory liability or asset associated with our renewable investments included in regulated rates is recorded in "Depreciation expense" on the Statements of Consolidated Income (Loss).

2. Recent Accounting Pronouncements

Recently Issued Accounting Pronouncements

We have evaluated recently issued accounting pronouncements and do not believe any pronouncements will have a significant impact on our Consolidated Financial Statements or Notes to the Consolidated Financial Statements.

Recently Adopted Accounting Pronouncements

In March 2020, the FASB issued ASU 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting* and in January 2021, the FASB issued ASU 2021-01, *Reference Rate Reform (Topic 848): Scope.* These pronouncements provide temporary optional expedients and exceptions for applying GAAP principles to contract modifications and hedging relationships to ease the financial reporting burdens of the expected market transition from LIBOR and other interbank offered rates to alternative reference rates. These pronouncements were effective upon issuance on March 12, 2020 through December 31, 2022. In December 2022, the FASB issued ASU 2022-06, *Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848*, to extend the temporary accounting rules under Topic 848 from December 31, 2022 to December 31, 2024, after which entities will no longer be permitted to apply the relief in Topic 848. During the third quarter of 2022, the company applied the practical expedient under Topic 848 which allowed for the continuation of cash flow hedge accounting for interest rate derivative contracts upon the transition from LIBOR to alternative reference rates. The application of this expedient had no material impact on the Consolidated Financial Statements.

In November 2021, the FASB issued ASU 2021-10, *Government Assistance (Topic 832): Disclosures by Business Entities about Government Assistance*. This pronouncement requires certain annual disclosures for transactions with a government that are accounted for by applying a grant or contribution accounting model by analogy to other accounting guidance. This pronouncement is effective for financial statements issued for annual periods beginning after December 15, 2021. The company adopted this pronouncement in the fourth quarter of 2022. The adoption of this pronouncement did not have an impact on the Notes to the Consolidated Financial Statements.

In September 2022, the FASB issued ASU 2022-04, *Liabilities-Supplier Finance Programs (Topic 405-50) - Disclosure of Supplier Finance Program Obligations*. This pronouncement requires that a buyer in a supplier finance program disclose sufficient information to allow a user of financial statements to understand the program's nature, activity during the period, changes from period to period, and potential magnitude. This pronouncement is expected to improve financial reporting by requiring new disclosures about supplier finance programs, thereby allowing financial statement users to better consider the effect of such programs on an entity's working capital, liquidity, and cash flows. This pronouncement is effective for fiscal years beginning after December 15, 2022. The company adopted this pronouncement as of January 1, 2023. We had no active supplier finance programs as of December 31, 2022.

3. Revenue Recognition

Customer Revenues. Substantially all of our revenues are tariff-based. Under ASC 606, the recipients of our utility service meet the definition of a customer, while the operating company tariffs represent an agreement that meets the definition of a contract, which creates enforceable rights and obligations. Customers in certain of our jurisdictions participate in programs that allow for a fixed payment each month regardless of usage. Payments received that exceed the value of gas or electricity actually delivered are recorded as a liability and presented in "Customer Deposits and Credits" on the Consolidated Balance Sheets. Amounts in this account are reduced and revenue is recorded when customer usage exceeds payments received.

We have identified our performance obligations created under tariff-based sales as 1) the commodity (natural gas or electricity, which includes generation and capacity) and 2) delivery. These commodities are sold and / or delivered to and generally consumed by customers simultaneously, leading to satisfaction of our performance obligations over time as gas or electricity is delivered to customers. Due to the at-will nature of utility customers, performance obligations are limited to the services requested and received to date. Once complete, we generally maintain no additional performance obligations.

Transaction prices for each performance obligation are generally prescribed by each operating company's respective tariff. Rates include provisions to adjust billings for fluctuations in fuel and purchased power costs and cost of natural gas. Revenues are adjusted for differences between actual costs, subject to reconciliation, and the amounts billed in current rates. Under or over recovered revenues related to these cost recovery mechanisms are included in "Regulatory Assets" or "Regulatory Liabilities" on the Consolidated Balance Sheets and are recovered from or returned to customers through adjustments to tariff rates. As we provide and deliver service to customers, revenue is recognized based on the transaction price allocated to each performance obligation. Distribution revenues are generally considered daily or "at-will" contracts as customers may cancel their service at any time (subject to notification requirements), and revenue generally represents the amount we are entitled to bill customers.

In addition to tariff-based sales, our Gas Distribution Operations segment enters into balancing and exchange arrangements of natural gas as part of our operations and off-system sales programs. Performance obligations for these types of sales include transportation and storage of natural gas and can be satisfied at a point in time or over a period of time, depending on the specific transaction. For those transactions that span a period of time, we record a receivable or payable for any cumulative gas imbalances, as well as for any gas inventory borrowed or lent under a Gas Distributions Operations exchange agreement.

Revenue Disaggregation and Reconciliation. We disaggregate revenue from contracts with customers based upon reportable segment as well as by customer class.

The tables below reconcile revenue disaggregation by customer class to segment revenue, as well as to revenues reflected on the Statements of Consolidated Income (Loss):

Year Ended December 31, 2022 (in millions)	Gas Distribution Operations	Electric Operations	Corporate and Other[(2)]	Total
Customer Revenues[(1)]				
Residential	$ 2,609.7	$ 592.4	$ —	$ 3,202.1
Commercial	939.6	571.0	—	1,510.6
Industrial	220.6	560.6	—	781.2
Off-system	192.9	—	—	192.9
Miscellaneous	40.3	11.5	—	51.8
Total Customer Revenues	$ 4,003.1	$ 1,735.5	$ —	$ 5,738.6
Other Revenues	4.1	95.4	12.5	112.0
Total Operating Revenues	$ 4,007.2	$ 1,830.9	$ 12.5	$ 5,850.6

(1)Customer revenue amounts exclude intersegment revenues. See Note 21, "Business Segment Information," for discussion of intersegment revenues.
(2)Other revenues related to the Transition Services Agreement entered into in connection with the sale of the Massachusetts Business, which was substantially completed as of June 30, 2022.

Year Ended December 31, 2021 *(in millions)*	Gas Distribution Operations	Electric Operations	Corporate and Other[(2)]	Total
Customer Revenues[(1)]				
Residential	$ 2,109.4	$ 567.9	$ —	$ 2,677.3
Commercial	722.4	534.9	—	1,257.3
Industrial	195.7	493.4	—	689.1
Off-system	71.3	—	—	71.3
Miscellaneous	27.3	8.2	0.8	36.3
Total Customer Revenues	$ 3,126.1	$ 1,604.4	$ 0.8	$ 4,731.3
Other Revenues	45.1	91.9	31.3	168.3
Total Operating Revenues	$ 3,171.2	$ 1,696.3	$ 32.1	$ 4,899.6

(1)Customer revenue amounts exclude intersegment revenues. See Note 21, "Business Segment Information," for discussion of intersegment revenues.
(2)Other revenues related to the Transition Services Agreement entered into in connection with the sale of the Massachusetts Business.

Year Ended December 31, 2020 *(in millions)*	Gas Distribution Operations	Electric Operations	Corporate and Other[(2)]	Total
Customer Revenues[(1)]				
Residential	$ 2,075.0	$ 527.8	$ —	$ 2,602.8
Commercial	670.5	480.3	—	1,150.8
Industrial	212.8	412.1	—	624.9
Off-system	41.0	—	—	41.0
Miscellaneous	32.7	20.2	0.8	53.7
Total Customer Revenues	$ 3,032.0	$ 1,440.4	$ 0.8	$ 4,473.2
Other Revenues	96.1	95.5	16.9	208.5
Total Operating Revenues	$ 3,128.1	$ 1,535.9	$ 17.7	$ 4,681.7

(1)Customer revenue amounts exclude intersegment revenues. See Note 21, "Business Segment Information," for discussion of intersegment revenues.
(2)Other revenues related to the Transition Services Agreement entered into in connection with the sale of the Massachusetts Business.

Other Revenues. As permitted by accounting principles generally accepted in the United States, regulated utilities have the ability to earn certain types of revenue that are outside the scope of ASC 606. These revenues primarily represent revenue earned under alternative revenue programs. Alternative revenue programs represent regulator-approved mechanisms that allow for the adjustment of billings and revenue for certain approved programs. We maintain a variety of these programs, including demand side management initiatives that recover costs associated with the implementation of energy efficiency programs, as well as normalization programs that adjust revenues for the effects of weather or other external factors. Additionally, we maintain certain programs with future test periods that operate similarly to FERC formula rate programs and allow for recovery of costs incurred to replace aging infrastructure. When the criteria to recognize alternative revenue have been met, we establish a regulatory asset and present revenue from alternative revenue programs on the Statements of Consolidated Income (Loss) as “Other revenues”. When amounts previously recognized under alternative revenue accounting guidance are billed, we reduce the regulatory asset and record a customer account receivable.

Customer Accounts Receivable. Accounts receivable on our Consolidated Balance Sheets includes both billed and unbilled amounts, as well as certain amounts that are not related to customer revenues. Unbilled amounts of accounts receivable relate to a portion of a customer’s consumption of gas or electricity from the date of the last cycle billing through the last day of the month (balance sheet date). Factors taken into consideration when estimating unbilled revenue include historical usage, customer rates and weather. A significant portion of our operations are subject to seasonal fluctuations in sales. During the heating season, primarily from November through March, revenues and receivables from gas sales are more significant than in other months. The opening and closing balances of customer receivables for the year ended December 31, 2022, are presented in the table below. We had no significant contract assets or liabilities during the period. Additionally, we have not incurred any significant costs to obtain or fulfill contracts.

(in millions)	Customer Accounts Receivable, Billed (less reserve)	Customer Accounts Receivable, Unbilled (less reserve)
Balance as of December 31, 2021	$ 459.6	$ 337.0
Balance as of December 31, 2022	560.5	453.0

Utility revenues are billed to customers monthly on a cycle basis. We expect that substantially all customer accounts receivable will be collected following customer billing, as this revenue consists primarily of periodic, tariff-based billings for service and usage. We maintain common utility credit risk mitigation practices, including requiring deposits and actively pursuing collection of past due amounts. Our regulated operations also utilize certain regulatory mechanisms that facilitate recovery of bad debt costs within tariff-based rates, which provides further evidence of collectibility. It is probable that substantially all of the consideration to which we are entitled from customers will be collected upon satisfaction of performance obligations.

Allowance for Credit Losses. To evaluate for expected credit losses, customer account receivables are pooled based on similar risk characteristics, such as customer type, geography, payment terms, and related macro-economic risks. Expected credit losses are established using a model that considers historical collections experience, current information, and reasonable and supportable forecasts. Internal and external inputs are used in our credit model including, but not limited to, energy consumption trends, revenue projections, actual charge-offs data, recoveries data, shut-offs, customer delinquencies, final bill data, and inflation. We continuously evaluate available information relevant to assessing collectability of current and future receivables. We evaluate creditworthiness of specific customers periodically or following changes in facts and circumstances. When we become aware of a specific commercial or industrial customer's inability to pay, an allowance for expected credit losses is recorded for the relevant amount. We also monitor other circumstances that could affect our overall expected credit losses; including, but not limited to, creditworthiness of overall population in service territories, adverse conditions impacting an industry sector, and current economic conditions.

At each reporting period, we record expected credit losses to an allowance for credit losses account. When deemed to be uncollectible, customer accounts are written-off. A rollforward of our allowance for credit losses as of December 31, 2022 and December 31, 2021, are presented in the tables below:

(in millions)	Gas Distribution Operations	Electric Operations	Corporate and Other	Total
Balance as of January 1, 2022	$ 18.9	$ 3.8	$ 0.8	$ 23.5
Current period provisions	29.1	6.9	—	36.0
Write-offs charged against allowance	(52.1)	(5.3)	—	(57.4)
Recoveries of amounts previously written off	21.3	0.5	—	21.8
Balance as of December 31, 2022	$ 17.2	$ 5.9	$ 0.8	$ 23.9

(in millions)	Gas Distribution Operations	Electric Operations	Corporate and Other	Total
Balance as of January 1, 2021	$ 41.8	$ 9.7	$ 0.8	$ 52.3
Current period provisions	5.8	1.4	—	7.2
Write-offs charged against allowance	(46.7)	(7.7)	—	(54.4)
Recoveries of amounts previously written off	18.0	0.4	—	18.4
Balance as of December 31, 2021	$ 18.9	$ 3.8	$ 0.8	$ 23.5

In connection with the COVID-19 pandemic, certain state regulatory commissions instituted regulatory moratoriums that impacted our ability to pursue our standard credit risk mitigation practices. Following the issuance of these moratoriums, certain of our regulated operations have been authorized to recognize a regulatory asset for bad debt costs above levels currently recovered in rates. At the balance sheet date, in addition to our evaluation of the allowance for credit losses discussed above, we considered benefits available under governmental COVID-19 relief programs, the impact of unemployment benefits initiatives, and flexible payment plans being offered to customers affected by or experiencing hardship as a result of the pandemic, which could help to mitigate the potential for increasing customer account delinquencies. We also considered the on-time bill payment promotion and robust customer marketing strategy for energy assistance programs that we have implemented. Based upon this evaluation, we have concluded that the allowance for credit losses as of December 31, 2022 adequately reflected the collection risk and net realizable value of our receivables. See Note 9, "Regulatory Matters," for additional information on regulatory moratoriums and regulatory assets.

4. Variable Interest Entities

A VIE is an entity in which the controlling interest is determined through means other than a majority voting interest. Refer to Note 1, "Nature of Operations and Summary of Significant Accounting Policies - S. VIEs and Allocation of Earnings," for information on our accounting policy for the VIEs.

NIPSCO owns and operates two wind facilities, Rosewater and Indiana Crossroads Wind, which have 102 MW and 302 MW of nameplate capacity, respectively. NIPSCO also owns one solar facility, which is expected to go into service in 2023, Indiana Crossroads Solar, which has 200 MW of nameplate capacity. We control decisions that are significant to these entities' ongoing operations and economic results. Therefore, we have concluded that we are the primary beneficiary and have consolidated all three entities.

Members of the respective JVs are NIPSCO (who is the managing member) and tax equity partners. Earnings, tax attributes and cash flows are allocated to both NIPSCO and the tax equity partner in varying percentages by category and over the life of the partnership. NIPSCO and each tax equity partner contributed cash, and NIPSCO also assumed an obligation to the developers of the wind facilities representing the remaining economic interest. The developers of the wind facilities are not a partner in the JV for federal income tax purposes and do not receive any share of earnings, tax attributes, or cash flows of each JV. Once the tax equity partner has earned their negotiated rate of return and we have reached the agreed upon contractual date, NIPSCO has the option to purchase at fair market value from the tax equity partner the remaining interest in the respective JV. NIPSCO has an obligation to purchase, through a PPA at established market rates, 100% of the electricity generated by the JVs.

The following table displays the total contributions paid and obligations incurred in the periods presented:

(in millions)		**December 31, 2022**		December 31, 2021		December 31, 2020
NIPSCO Cash Contributions	**$**	**151.8**	$	2.8	$	0.7
Tax Equity Partner Cash Contributions		**21.2**		245.1		86.1
NIPSCO's Obligation to Developer[1]		**—**		277.5		69.7
Total Contributions	**$**	**173.0**	$	525.4	$	156.5

[1] Outstanding amounts in "Obligations to renewable generation asset developer" in the Consolidated Balance Sheets.

We did not provide any financial or other support during the year that was not previously contractually required, nor do we expect to provide such support in the future.

Our Consolidated Balance Sheets included the following assets and liabilities associated with VIEs.

(in millions)		**December 31, 2022**		December 31, 2021
Net Property, Plant and Equipment	**$**	**978.5**	$	695.9
Current assets		**25.7**		14.3
Total assets[1]		**1,004.2**		710.2
Current liabilities		**128.2**		10.0
Asset retirement obligations		**30.6**		20.5
Total liabilities	**$**	**158.8**	$	30.5

[1]The assets of each VIE represent assets of a consolidated VIE that can be used only to settle obligations of the respective consolidated VIE. The creditors of the liabilities of the VIEss do not have recourse to the general credit of the primary beneficiary.

5. Earnings Per Share

The calculations of basic and diluted EPS are based on the weighted average number of shares of common stock and potential common stock outstanding during the period. For the purposes of determining diluted EPS, the shares underlying the purchase contracts included within the Equity Units were included in the calculation of potential common stock outstanding for the years ended December 31, 2022 and 2021 using the if-converted method under US GAAP. This method assumes conversion at the beginning of the reporting period, or at time of issuance, if later. For the purchase contracts, the number of shares of our common stock that would be issuable at the end of each reporting period will be reflected in the denominator of our diluted EPS calculation. If the stock price falls below the initial reference price of $24.51, subject to anti-dilution adjustments, the number of shares of our common stock used in calculating diluted EPS will be the maximum number of shares per the contract as described in Note 13, "Equity." Conversely, if the stock price is above the initial reference price of $24.51, subject to anti-dilution adjustments, a variable number of shares of our common stock will be used in calculating diluted EPS. A numerator adjustment was reflected in the calculation of diluted EPS for interest expense incurred in 2022 and 2021, net of tax, related to the purchase contracts.

We adopted ASU 2020-06 on January 1, 2022, which resulted in additional dilution from our Equity Units by requiring us to assume share settlement of the remaining purchase contract payment balance based on the average share price during the period.

The shares underlying the Series C Mandatory Convertible Preferred Stock included within the Equity Units are contingently convertible as the conversion is contingent on a successful remarketing as described in Note 13, "Equity." Contingently convertible shares where conversion is not tied to a market price trigger are excluded from the calculation of diluted EPS until such time as the contingency has been resolved under the if-converted method. As of December 31, 2022 and 2021, the contingency was not resolved and thus no shares were reflected in the denominator in the calculation of diluted EPS for the years ended December 31, 2022 and 2021.

Diluted EPS also includes the incremental effects of the various long-term incentive compensation plans and the open ATM forward agreements during the period under the treasury stock method when the impact would be dilutive. Refer to Note 13, "Equity," for more information on our ATM forward agreements.

For the year ended December 31, 2020, we had a net loss on the Statements of Consolidated Income (Loss) during the period, and any potentially dilutive shares would have had an anti-dilutive impact on EPS. The following table presents the calculation of our basic and diluted EPS:

Year Ended December 31, *(in millions, except per share amounts)*		**2022**		2021		2020
Numerator:						
Net Income (Loss) Available to Common Shareholders - Basic	**$**	**749.0**	$	529.8	$	(72.7)
Dilutive effect of Equity Units		**2.0**		1.6		—
Net Income (Loss) Available to Common Shareholders - Diluted	**$**	**751.0**	$	531.4	$	(72.7)
Denominator:						
Average common shares outstanding - Basic		**407.1**		393.6		384.3
Dilutive potential common shares:						
Equity Units purchase contracts		**30.2**		22.0		—
Equity Units purchase contract payment balance		**3.2**		—		—
Shares contingently issuable under employee stock plans		**0.9**		0.8		—
Shares restricted under employee stock plans		**0.5**		0.3		—
ATM Forward agreements		**0.8**		0.6		—
Average Common Shares - Diluted		**442.7**		417.3		384.3
Earnings per common share:						
Basic	**$**	**1.84**	$	1.35	$	(0.19)
Diluted	**$**	**1.70**	$	1.27	$	(0.19)

6. Property, Plant and Equipment

Our property, plant and equipment on the Consolidated Balance Sheets are classified as follows:

At December 31, *(in millions)*		**2022**		2021
Property, Plant and Equipment				
Gas Distribution Utility[1]	**$**	**16,576.4**	$	15,240.6
Electric Utility[1]		**7,162.4**		6,754.9
Corporate		**271.7**		217.8
Construction Work in Process		**1,398.2**		808.0
Renewable Generation Assets[2]		**702.2**		702.4
Non-Utility and Other		**1,440.4**		1,447.6
Total Property, Plant and Equipment	**$**	**27,551.3**	$	25,171.3
Accumulated Depreciation and Amortization				
Gas Distribution Utility[1]	**$**	**(3,678.1)**	$	(3,490.2)
Electric Utility[1]		**(2,557.4)**		(2,433.1)
Corporate		**(160.0)**		(132.2)
Renewable Generation Assets[2]		**(29.7)**		(6.5)
Non-Utility and Other		**(1,283.5)**		(1,227.5)
Total Accumulated Depreciation and Amortization	**$**	**(7,708.7)**	$	(7,289.5)
Net Property, Plant and Equipment	**$**	**19,842.6**	$	17,881.8

[1]NIPSCO's common utility plant and associated accumulated depreciation and amortization are allocated between Gas Distribution Utility and Electric Utility Property, Plant and Equipment.
[2]Our renewable generation assets are part of our electric segment and represent Non-Utility Property, owned and operated by JVs between NIPSCO and unrelated tax equity partners, and depreciated straight-line over 30 years. Refer to Note 4, "Variable Interest Entities," for additional information.

On October 1, 2021, NIPSCO retired R.M. Schahfer Generating Station Units 14 and 15. The net book value of the retired units was reclassified from "Net Property, Plant and Equipment," to current and long-term "Regulatory Assets." The estimated net book value of R.M. Schahfer Generating Station's coal Units 14 and 15 and other associated plant retired was approximately $600.0 million. See Note 9, "Regulatory Matters," for additional details regarding the recovery of the regulatory assets associated with retired generating stations.

The weighted average depreciation provisions for utility plant, as a percentage of the original cost, for the periods ended December 31, 2022, 2021 and 2020 were as follows:

	2022	2021	2020
Electric Operations	**3.1 %**	3.4 %	3.4 %
Gas Distribution Operations	**2.3 %**	2.2 %	2.3 %

We recognized depreciation expense of $685.0 million, $672.1 million and $655.6 million for the years ended 2022, 2021 and 2020, respectively. The 2022 and 2021 depreciation expense amounts include an $11.0 million and $5.3 million increase related to the regulatory deferral of income (loss) associated with our JVs, which is not included in current rates. See Note 9, "Regulatory Matters," for additional details.

Amortization of on-premise Software Costs. We amortized $53.1 million, $49.4 million and $56.7 million in 2022, 2021 and 2020, respectively, related to software recorded as intangible assets. Our unamortized software balance was $190.1 million and $181.8 million at December 31, 2022 and 2021, respectively.

Amortization of Cloud Computing Costs. We amortized $11.1 million, $10.0 million and $3.4 million in 2022, 2021 and 2020, respectively, related to cloud computing costs to "Operation and maintenance" expense. Our unamortized cloud computing balance was $45.7 million and $42.4 million at December 31, 2022 and 2021, respectively.

7. Goodwill

Substantially all of our goodwill relates to the excess of cost over the fair value of the net assets acquired in the Columbia acquisition on November 1, 2000. Our goodwill balance was $1,485.9 million as of December 31, 2022 and 2021. All our goodwill has been allocated to our Gas Distribution Operations segment.

For our annual goodwill impairment analysis performed as of May 1, 2022, we completed a qualitative "step 0" assessment and determined that it was more likely than not that the estimated fair value of the reporting unit substantially exceeded the related carrying value of our reporting unit. For this test, we assessed various assumptions, events and circumstances that would have affected the estimated fair value of the reporting units as compared to the baseline "step 1" fair value measurement performed May 1, 2020.

8. Asset Retirement Obligations

We have recognized asset retirement obligations associated with various legal obligations including costs to remove and dispose of certain construction materials located within many of our facilities (including our JV facilities), certain costs to retire pipeline, removal costs for certain underground storage tanks, removal of certain pipelines known to contain PCB contamination, closure costs for certain sites including ash ponds, solid waste management units and a landfill, as well as some other nominal asset retirement obligations. We also have an obligation associated with the decommissioning of our two hydro facilities located in Indiana. These hydro facilities have an indeterminate life, and as such, no asset retirement obligation has been recorded.

Changes in our liability for asset retirement obligations for the years 2022 and 2021 are presented in the table below:

(in millions)	**2022**	2021
Beginning Balance	**$ 512.4**	$ 495.6
Accretion recorded as a regulatory asset/liability	**17.1**	16.0
Additions	**9.5**	23.2
Settlements	**(22.3)**	(11.2)
Change in estimated cash flows	**(3.2)**	(11.2)
Ending Balance	**$ 513.5**	$ 512.4

Certain non-legal costs of removal that have been, and continue to be, included in depreciation rates and collected in the customer rates of the rate-regulated subsidiaries are classified as "Regulatory liabilities" on the Consolidated Balance Sheets.

9. Regulatory Matters

Regulatory Assets and Liabilities

We follow the accounting and reporting requirements of ASC Topic 980, which provides that regulated entities account for and report assets and liabilities consistent with the economic effect of regulatory rate-making procedures when the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates will be charged and collected from customers. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income or expense are deferred on the balance sheet and are recognized in the income statement as the related amounts are included in customer rates and recovered from or refunded to customers. We assess the probability of collection for all of our regulatory assets each period.

Regulatory assets were comprised of the following items:

At December 31, *(in millions)*		2022		2021
Regulatory Assets				
Unrecognized pension and other postretirement benefit costs (see Note 12)	**$**	**607.5**	$	512.1
Deferred pension and other postretirement benefit costs (see Note 12)		**72.2**		74.8
Environmental costs (see Note 19-E.)		**41.4**		45.8
Regulatory effects of accounting for income taxes (see Note 1-N. and Note 11)		**158.0**		194.8
Under-recovered gas and fuel costs (see Note 1-J.)		**85.5**		73.6
Depreciation		**191.3**		177.5
Post-in-service carrying charges		**251.5**		237.9
Safety activity costs		**200.7**		171.9
DSM programs		**37.5**		39.2
Retired coal generating stations		**744.0**		803.9
Losses on commodity price risk programs (See Note 10)		**10.0**		9.6
Deferred property taxes		**68.5**		65.1
Renewable energy investments (See Note 1-S. and Note 4)		**37.7**		18.5
Other		**75.0**		67.5
Total Regulatory Assets	**$**	**2,580.8**	$	2,492.2
Less: Current Portion		**233.2**		206.2
Total Noncurrent Regulatory Assets	**$**	**2,347.6**	$	2,286.0

Regulatory liabilities were comprised of the following items:

At December 31, *(in millions)*		2022		2021
Regulatory Liabilities				
Over-recovered gas and fuel costs (see Note 1-J.)	**$**	**20.6**	$	5.4
Cost of removal (see Note 8)		**675.9**		749.5
Regulatory effects of accounting for income taxes (see Note 1-N. and Note 11)		**996.3**		1,040.8
Deferred pension and other postretirement benefit costs (see Note 12)		**66.8**		75.9
Gains on commodity price risk programs (See Note 10)		**90.0**		34.2
Customer Assistance Programs		**32.9**		13.2
Rate Refunds		**51.4**		8.2
Other		**78.7**		52.8
Total Regulatory Liabilities	**$**	**2,012.6**	$	1,980.0
Less: Current Portion		**236.8**		137.4
Total Noncurrent Regulatory Liabilities	**$**	**1,775.8**	$	1,842.6

Regulatory assets, including under-recovered gas and fuel costs and depreciation, of approximately $1,324.7 million and $1,207.0 million as of December 31, 2022 and 2021, respectively, are not earning a return on investment. These costs are recovered over a remaining life, the longest of which is 50 years.

Assets:

Unrecognized pension and other postretirement benefit costs. Represents the deferred other comprehensive income or loss of the actuarial gains or losses and the prior service costs or credits that arise during the period but that are not immediately recognized as components of net periodic benefit costs by certain subsidiaries that will ultimately be recovered through base rates.

Deferred pension and other postretirement benefit costs. Primarily relates to the difference between defined benefit plan expense recorded by certain subsidiaries due to regulatory orders and the corresponding expense that would otherwise be recorded in accordance with GAAP. The majority of these amounts are driven by Columbia of Ohio. On January 26, 2023, the PUCO approved the joint stipulation in Columbia of Ohio's rate case. In the stipulation, Columbia agreed to forego the continuation of its pension and OPEB deferral prospectively as of March 31, 2021. Amounts deferred as of March 31, 2021 will be included in base rates.

Environmental costs. Includes certain recoverable costs related to gas plant sites, disposal sites or other sites onto which material may have migrated, the recovery of which is to be addressed in future base rates, billing riders or tracking mechanisms of certain of our subsidiaries.

Regulatory effects of accounting for income taxes. Represents the deferral and under collection of deferred taxes in the rate making process.

Under-recovered gas and fuel costs. Represents the difference between the costs of gas and fuel and the recovery of such costs in revenue and is used to adjust future billings for such deferrals on a basis consistent with applicable state-approved tariff provisions. Recovery of these costs is achieved through tracking mechanisms.

Depreciation. Represents differences between depreciation expense incurred on a GAAP basis and that prescribed through regulatory order. The majority of this balance is driven by Columbia of Ohio's IRP and CEP deferrals, however, starting in March 2023, the majority of these costs will be in base rates.

Post-in-service carrying charges. Represents deferred debt-based carrying charges incurred on certain assets placed into service but not yet included in customer rates. The majority of this balance is driven by Columbia of Ohio's IRP and CEP deferrals, however, starting in March 2023, the majority of these costs will be in base rates.

Safety activity costs. Represents the difference between costs incurred by certain of our subsidiaries in eligible safety programs in compliance with PHMSA regulations in excess of those being recovered in rates. The majority of this balance is driven by Columbia of Ohio, which will begin recovery in March 2023 through base rates.

DSM programs. Represents costs associated with Gas Distribution Operations and Electric Operations segments' energy efficiency and conservation programs. Costs are recovered through tracking mechanisms.

Retired coal generating stations. Represents the net book value of Units 7 and 8 of Bailly Generating Station that was retired during 2018 and the net book value of Units 14 and 15 of R.M. Schahfer Generating Station retired in 2021. These amounts are currently being amortized at a rate consistent with their inclusion in customer rates. The December 2019 NIPSCO electric rate case order allows for the recovery of, and on, the net book value of the stations by the end of 2032 and implements a revenue credit for the retired units. The credit is based on the difference between the net book value of Units 14 and 15 upon retirement and the last base rate case proceeding. The credit will be reset when new base rates are determined. See Note 6, "Property, Plant and Equipment," for further details.

Losses on commodity price risk programs. Represents the unrealized losses related to certain of our subsidiary's commodity price risk programs. These programs help to protect against the volatility of commodity prices and these amounts are collected from customers through their inclusion in customer rates.

Deferred property taxes. Represents the deferral and under collection of property taxes in the rate making process for Columbia of Ohio and is driven by the IRP and CEP deferrals, however, starting in March 2023, the majority of these costs will be in base rates.

Renewable energy investments. Represents the regulatory deferral of certain amounts representing the timing difference between the profit earned from the JVs and the amount included in regulated rates to recover our approved investments in consolidated JVs. These amounts will be collected through base rates over the life of the renewable generating assets to which they relate. Refer to Note 1, "Nature of Operations and Summary of Significant Accounting Policies - S. VIEs and Allocation of Earnings," for additional information. Renewable energy formation and developer costs are also included in this regulatory asset.

Liabilities:

Over-recovered gas and fuel costs. Represents the difference between the cost of gas and fuel and the recovery of such costs in revenues and is the basis to adjust future billings for such refunds on a basis consistent with applicable state-approved tariff provisions. Refunding of these revenues is achieved through tracking mechanisms.

Cost of removal. Represents anticipated costs of removal for utility assets that have been collected through depreciation rates for future costs to be incurred.

Regulatory effects of accounting for income taxes. Represents amounts owed to customers for deferred taxes collected at a higher rate than the current statutory rates and liabilities associated with accelerated tax deductions owed to customers. Balance includes excess deferred taxes recorded upon implementation of the TCJA in December 2017, net of amounts amortized through 2022.

Deferred pension and other postretirement benefit costs. Primarily represents cash contributions in excess of postretirement benefit expense that is deferred by certain subsidiaries.

Gains on commodity price risk programs. Represents the unrealized gains related to certain of our subsidiary's commodity price risk programs. These programs help to protect against the volatility of commodity prices, and these amounts are passed back to customers through their inclusion in customer rates.

Customer Assistance Programs. Represents the difference between the eligible customer assistance program costs and collections, which will be refunded to customers.

Rate Refunds. Represents supplier refunds received by the company that are owed to customers and will be remitted.

NIPSCO change in accounting estimate

As part of the NIPSCO Gas Settlement and Stipulation Agreement filed on March 2, 2022, NIPSCO Gas agreed to change the depreciation methodology for its calculation of depreciation rates, which reduces depreciation expense and subsequent revenues and cash flows. An order was received on July 27, 2022 approving the rate case and rates were effective as of September 1, 2022. NIPSCO has proposed a similar change in depreciation methodology in its pending electric base rate case.

Columbia of Ohio regulatory filing update

On Wednesday, April 6, 2022, the PUCO Staff issued its Staff Report in Columbia of Ohio's base rate case, filed on June 21, 2021, which was filed in conjunction with applications for an alternative rate plan, approval of certain deferral authority, and updates to certain riders. Columbia of Ohio's application requested a net rate increase approximating a 21.3% or $221.4 million increase in revenue per year. On October 31, 2022, Columbia of Ohio filed a joint stipulation and recommendation with certain parties to settle the base rate case. The joint stipulation and recommendation includes a rate increase of 7.97%, or $68.2 million and includes adjustments to plant assets, pension expenses, environmental remediation costs and other operations and maintenance expenses. The joint stipulation and recommendation also proposes to extend both of Columbia of Ohio's capital investment riders, the IRP and CEP, for capital invested through the 2026 calendar year. Columbia of Ohio recorded the material effects of the joint stipulation in the fourth quarter. On January 26, 2023, the PUCO approved the joint stipulation and recommendation.

Regulatory deferral related to renewable energy investments

The offset to the regulatory liability or asset associated with our renewable investments included in regulated rates is recorded in "Depreciation expense" on the Statements of Consolidated Comprehensive Income (Loss). Refer to Note 4, "Variable Interest Entities," and Note 6, "Property, Plant and Equipment," for additional information.

FAC Adjustment

As ordered by the IURC on June 15, 2022, NIPSCO is required to refund to customers $8.0 million of over-collected fuel costs. The remaining refund is recorded as a regulatory liability on the Consolidated Balance Sheets and is expected to be refunded in 2023.

COVID-19 Regulatory Filings

In response to COVID-19, we received approvals or directives from the regulatory commissions in the states in which we operate. The ongoing impacts of these approvals or directives are described in the table below:

Jurisdiction	Regulatory Asset balance as of December 31, 2022 *(in millions)*	Regulatory Asset balance as of December 31, 2021 *(in millions)*	Deferred COVID-19 Costs
Columbia of Ohio	$ —	$ 2.1	Incremental operation and maintenance expenses
NIPSCO	$ 2.1	$ 2.2	Incremental bad debt expense and the costs to implement the requirements of the COVID-19 related order
Columbia of Pennsylvania	$ 2.8	$ 5.2	Incremental bad debt expense incurred from March 13, 2020 through December 29, 2021, above levels currently in rates
Columbia of Virginia	$ 1.9	$ 1.5	Incremental incurred costs, including incremental bad debt expense
Columbia of Maryland	$ 1.3	$ 0.9	Incremental costs (including incremental bad debt expense) incurred to ensure that customers have essential utility service during the state of emergency in Maryland. Such incremental costs must be offset by any benefit received in connection with the pandemic

On January 26, 2023, the PUCO approved the joint stipulation in Columbia of Ohio's rate case. As part of this stipulation, Columbia agreed to forego recovery of its deferred COVID-19 costs.

The Pennsylvania PUC lifted its prior pandemic-related moratorium on service terminations for non-payments of utility bills beginning April 1, 2021. In CPA's recent rate case order, total COVID-19 deferrals were updated with the remaining balance being amortized over a four-year period.

For Columbia of Virginia, the moratorium on non-residential disconnections ended on October 6, 2020, and the moratorium on residential disconnections and late payment fees ended on August 30, 2021.

In connection with the Maryland Relief Act and the order issued by the PSC of Maryland on June 15, 2021, Columbia of Maryland received approximately $0.8 million of assistance that was applied to customer accounts in August 2021. Columbia of Maryland's recent rate case order includes continued amortization of operation and maintenance expenses. All termination moratoriums will be lifted after April 1, 2023 and normal collections procedures will be resumed.

Unless otherwise noted above, all other pandemic-related regulatory actions have expired or been lifted.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

10. Risk Management Activities

We are exposed to certain risks related to our ongoing business operations; namely commodity price risk and interest rate risk. We recognize that the prudent and selective use of derivatives may help to lower our cost of debt capital, manage interest rate exposure and limit volatility in the price of natural gas.

Risk management assets and liabilities on our derivatives are presented on the Consolidated Balance Sheets as shown below:

	December 31, 2022		December 31, 2021	
(in millions)	**Assets**	**Liabilities**	**Assets**	**Liabilities**
Current[(1)]				
Derivatives designated as hedging instruments	$ —	$ —	$ —	$ 136.4
Derivatives not designated as hedging instruments	**18.8**	**1.1**	10.6	0.4
Total	$ **18.8**	$ **1.1**	$ 10.6	$ 136.8
Noncurrent[(2)]				
Derivatives designated as hedging instruments	$ —	$ —	$ —	$ —
Derivatives not designated as hedging instruments	**66.0**	**1.9**	13.8	7.4
Total	$ **66.0**	$ **1.9**	$ 13.8	$ 7.4

(1) Presented in "Prepayments and other" and "Other accruals", respectively, on the Consolidated Balance Sheets.
(2) Presented in "Deferred charges and other" and "Other noncurrent liabilities", respectively, on the Consolidated Balance Sheets.

Our derivative instruments are subject to enforceable master netting arrangements or similar agreements. No collateral was either received or posted related to our outstanding derivative positions at December 31, 2022. If the above gross asset and liability positions were presented net of amounts owed or receivable from counterparties, we would report a net asset position of $81.8 million and $16.6 million at December 31, 2022 and 2021, respectively.

Derivatives Not Designated as Hedging Instruments
C***ommodity price risk management.*** We, along with our utility customers, are exposed to variability in cash flows associated with natural gas purchases and volatility in natural gas prices. We purchase natural gas for sale and delivery to our retail, commercial and industrial customers, and for most customers the variability in the market price of gas is passed through in their rates. Some of our utility subsidiaries offer programs whereby variability in the market price of gas is assumed by the respective utility. The objective of our commodity price risk programs is to mitigate the gas cost variability, for us or on behalf of our customers, associated with natural gas purchases or sales by economically hedging the various gas cost components using a combination of futures, options, forwards or other derivative contracts. As of December 31, 2022 and 2021, we had 99.0 MMDth and 124.5 MMDth, respectively, of net energy derivative volumes outstanding related to our natural gas hedges.

NIPSCO has received IURC approval to lock in a fixed price for its natural gas customers using long-term forward purchase instruments and is limited to 20% of NIPSCO's average annual GCA purchase volume. As of December 31, 2022, the remaining terms of these instruments range from one to five years.

All gains and losses on these derivative contracts are deferred as regulatory liabilities or assets and are remitted to or collected from customers through NIPSCO's quarterly GCA mechanism. These instruments are not designated as hedging instruments. Refer to Note 9, "Regulatory Matters," for additional information.

Derivatives Designated as Hedging Instruments
Interest rate risk management. As of December 31, 2022, we have no forward-starting interest rate swaps outstanding.

On June 7, 2022, we settled a $250.0 million forward-starting interest rate swap agreement contemporaneously with the issuance of $350.0 million of 5.00% senior unsecured notes maturing in 2052. The derivative contract was accounted for as a cash flow hedge. As part of the transaction, the associated net unrealized gain position of $10.2 million is being amortized from AOCI into interest expense over the life of the associated debt. Refer to Note 15, "Long-Term Debt," for additional information.

On December 21, 2022, we settled a $250.0 million forward-starting interest rate swap agreement that was designated as a cash flow hedge. As part of the transaction, the associated net unrealized gain position of $10.0 million was recognized immediately in "Other, net" on the Statements of Consolidated Income (Loss) due to the probability that the forecasted borrowing transaction would no longer occur.

Cash flow hedges included in "Accumulated other comprehensive loss" on the Consolidated Balance Sheets were:

(in millions)		AOCI[(1)]	Gain Expected to be Reclassified to Earnings During the Next 12 Months[(1)]	Maximum Term
Interest Rate	$	(12.6)	(0.3)	353 months

(1) All amounts are net of tax.

The net gain related to these swaps are recorded to AOCI. We amortize the net gain over the life of the debt associated with these swaps as we recognize interest expense. These amounts are immaterial in 2022, 2021 and 2020 and are recorded in "Interest expense, net" on the Statements of Consolidated Income (Loss).

There were no amounts excluded from effectiveness testing for derivatives in cash flow hedging relationships at December 31, 2021 and 2020.

Our derivative instruments measured at fair value as of December 31, 2022 and 2021 did not contain any credit-risk-related contingent features. Cash flows for derivative financial instruments are generally classified as operating activities.

11. Income Taxes

Income Tax Expense. The components of income tax expense (benefit) were as follows:

Year Ended December 31, *(in millions)*	**2022**	2021	2020
Income Taxes			
Current			
Federal	**$ 0.4**	$ (0.1)	$ 0.2
State	**7.3**	6.0	11.7
Total Current	**7.7**	5.9	11.9
Deferred			
Federal	**181.0**	99.2	(0.4)
State	**(23.0)**	13.8	(27.4)
Total Deferred	**158.0**	113.0	(27.8)
Deferred Investment Credits	**(1.1)**	(1.1)	(1.2)
Income Taxes	**$ 164.6**	$ 117.8	$ (17.1)

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

Statutory Rate Reconciliation. The following table represents a reconciliation of income tax expense at the statutory federal income tax rate to the actual income tax expense from continuing operations:

Year Ended December 31, *(in millions)*	**2022**		2021		2020	
Book income (loss) before income taxes	**$ 956.4**		$ 706.6		$ (31.3)	
Tax expense (benefit) at statutory federal income tax rate	**200.8**	**21.0 %**	148.3	21.0 %	(6.6)	21.0 %
Increases (reductions) in taxes resulting from:						
State income taxes, net of federal income tax benefit	**4.5**	**0.5**	14.1	2.0	(11.7)	37.4
Amortization of regulatory liabilities	**(38.5)**	**(4.0)**	(39.1)	(5.5)	(38.4)	122.7
Fines and penalties	**0.3**	**—**	—	—	11.8	(37.7)
Employee stock ownership plan dividends and other compensation	**(1.2)**	**(0.1)**	(1.2)	(0.2)	(1.3)	4.2
Deferred taxes on TCJA regulatory liability divested	**—**	**—**	—	—	23.3	(74.5)
Tax accrual adjustments	**0.2**	**—**	(0.1)	—	8.9	(28.4)
Federal tax credits	**(2.3)**	**(0.2)**	(2.1)	(0.3)	(2.5)	8.0
Other adjustments	**0.8**	**—**	(2.1)	(0.3)	(0.6)	1.9
Income Taxes	**$ 164.6**	**17.2 %**	$ 117.8	16.7 %	$ (17.1)	54.6 %

The difference in tax expense year-over-year has a relative impact on the effective tax rate proportional to pretax income or loss. The 0.5% increase in effective tax rate in 2022 versus 2021 was primarily due to decreased amortization of excess deferred income taxes, offset by the state jurisdictional mix of pre-tax income in 2022 tax effected at statutory tax rates, and the reduction of the Pennsylvania corporate income tax rate.

The 37.9% decrease in effective tax rate in 2021 versus 2020 was primarily the result of higher pre-tax income, state jurisdictional mix of pre-tax income in 2021 tax effected at statutory tax rates and increased amortization of excess deferred federal income taxes in 2021 compared to 2020. These items were offset by decreased deferred tax expense recognized on the sale of Columbia of Massachusetts' regulatory liability in 2020, established due to TCJA in 2017, that would have otherwise been recognized over the amortization period, 2020 non-deductible penalties and valuation allowance related to Columbia of Massachusetts and 2020 one-time tax accrual adjustments.

Net Deferred Income Tax Liability Components. Deferred income taxes result from temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The principal components of our net deferred tax liability were as follows:

At December 31, *(in millions)*	**2022**	2021
Deferred tax liabilities		
Accelerated depreciation and other property differences	**$ 2,527.9**	$ 2,454.4
Other regulatory assets	**348.4**	308.6
Total Deferred Tax Liabilities	**2,876.3**	2,763.0
Deferred tax assets		
Other regulatory liabilities and deferred investment tax credits (including TCJA)	**294.3**	284.7
Pension and other postretirement/postemployment benefits	**124.7**	104.8
Net operating loss carryforward and AMT credit carryforward	**491.0**	545.9
Environmental liabilities	**20.7**	22.2
Other accrued liabilities	**55.9**	42.1
Other, net	**43.0**	111.7
Total Deferred Tax Assets	**1,029.6**	1,111.4
Valuation Allowance	**(7.8)**	(7.8)
Net Deferred Tax Assets	**1,021.8**	1,103.6
Net Deferred Tax Liabilities	**$ 1,854.5**	$ 1,659.4

At December 31, 2022, we have federal net operating loss carryforwards of $410.0 million (tax effected). The federal net operating loss carryforwards are available to offset taxable income and will begin to expire in 2036. We believe it is more likely than not that we will realize the benefit from the federal net operating loss carryforwards.

We also have $73.2 million (tax effected, net of federal benefit) of state net operating loss carryforwards. Depending on the jurisdiction in which the state net operating loss was generated, the carryforwards will begin to expire in 2028.

We believe it is more likely than not that a portion of the benefit from certain state NOL carryforwards will not be realized. In recognition of this risk, we have provided a valuation allowance of $7.8 million (net) on the deferred tax assets related to sale of Massachusetts Business assets reflected in the state net operating loss carryforward presented above.

Unrecognized Tax Benefits. A reconciliation of the beginning and ending amounts of unrecognized tax benefits is as follows:

At December 31, 2022, *(in millions)*	**2022**	2021	2020
Opening Balance	**$ 21.7**	$ 21.7	$ 23.2
Gross decreases - tax positions in prior period	**—**	—	(1.5)
Gross increases - current period tax positions	**—**	—	—
Ending Balance	**$ 21.7**	$ 21.7	$ 21.7
Offset for net operating loss carryforwards	**(21.7)**	(21.7)	(21.7)
Balance, Less Net Operating Loss Carryforwards	**$ —**	$ —	$ —

We present accrued interest on unrecognized tax benefits, accrued interest on other income tax liabilities and tax penalties in "Income Taxes" on our Statements of Consolidated Income (Loss). Interest expense recorded on unrecognized tax benefits and other income tax liabilities was immaterial for all periods presented. There were no accruals for penalties recorded in the Statements of Consolidated Income (Loss) for the years ended December 31, 2022, 2021 and 2020, and there were no balances for accrued penalties recorded on the Consolidated Balance Sheets as of December 31, 2022 and 2021.

We are subject to income taxation in the United States and various state jurisdictions, primarily Indiana, Pennsylvania, Kentucky, Massachusetts, Maryland and Virginia.

We participate in the IRS CAP, which provides the opportunity to resolve tax matters with the IRS before filing each year's consolidated federal income tax return. As of December 31, 2022, tax years through 2021 have been audited and are effectively closed to further assessment. The Company has transitioned to the Bridge Phase of the IRS CAP for the year ended December 31, 2022, which will remain open until an audit is completed or the statute of limitation expires.

The statute of limitations in each of the state jurisdictions in which we operate remains open between 3-4 years from the date the state income tax returns are filed. As of December 31, 2022, there were no state income tax audits in progress that would have a material impact on the consolidated financial statements.

12. Pension and Other Postemployment Benefits

We provide defined contribution plans and noncontributory defined benefit retirement plans that cover certain of our employees. Benefits under the defined benefit retirement plans reflect the employees' compensation, years of service and age at retirement. Additionally, we provide health care and life insurance benefits for certain retired employees. The majority of employees may become eligible for these benefits if they reach retirement age while working for us. The expected cost of such benefits is accrued during the employees' years of service. Current rates of rate-regulated companies include postretirement benefit costs, including amortization of the regulatory assets that arose prior to inclusion of these costs in rates. For most plans, cash contributions are remitted to grantor trusts.

Our Pension and Other Postretirement Benefit Plans' Asset Management. The Board has delegated oversight of the pension and other postretirement benefit plans' assets to the NiSource Benefits Committee ("the Committee"). The Committee has adopted investment policy statements for the pension and other postretirement benefit plans' assets. For the pension plans, we employ a liability-driven investing strategy. A total return approach is utilized for the other postretirement benefit plans' assets. A mix of diversified investments are used to maximize the long-term return of plan assets and hedge the liabilities at a prudent level of risk. The investment portfolio includes U.S. and non-U.S. equities, real estate, long-term and intermediate-term fixed income and alternative investments. Risk tolerance is established through careful consideration of plan liabilities, funded status, and asset class volatility. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

In determining the expected long-term rate of return on plan assets, historical markets are studied, relationships between equities and fixed income are analyzed and current market factors, such as inflation and interest rates are evaluated with consideration of diversification and rebalancing. Our expected long-term rate of return on assets is based on assumptions regarding target asset allocations and corresponding long-term capital market assumptions for each asset class. The pension plans' investment policy calls for a gradual reduction in the allocation of return-seeking assets (equities, real estate and private equity) and a corresponding increase in the allocation of liability-hedging assets (fixed income) as the funded status of the plans' increase.

As of December 31, 2022 and December 31, 2021, the acceptable minimum and maximum ranges established by the policy for the pension and other postretirement benefit plans are as follows:

December 31, 2022	Defined Benefit Pension Plan		Postretirement Benefit Plan	
Asset Category	Minimum	Maximum	Minimum	Maximum
Domestic Equities	7%	27%	0%	55%
International Equities	3%	13%	0%	25%
Fixed Income	69%	81%	20%	100%
Real Estate	0%	3%	0%	0%
Private Equity	0%	3%	0%	0%
Short-Term Investments	0%	10%	0%	10%

December 31, 2021	Defined Benefit Pension Plan		Postretirement Benefit Plan	
Asset Category	Minimum	Maximum	Minimum	Maximum
Domestic Equities	7%	27%	0%	55%
International Equities	3%	13%	0%	25%
Fixed Income	69%	81%	20%	100%
Real Estate	0%	3%	0%	0%
Private Equity	0%	3%	0%	0%
Short-Term Investments	0%	10%	0%	10%

The actual Pension Plan and Postretirement Plan Asset Mix at December 31, 2022 and December 31, 2021 are as follows:

	Defined Benefit Pension Assets[1]	December 31, 2022	Postretirement Benefit Plan Assets	December 31, 2022
Asset Class *(in millions)*	Asset Value	% of Total Assets	Asset Value	% of Total Assets
Domestic Equities	$ 231.1	16.2 %	$ 86.9	38.6 %
International Equities	119.0	8.4 %	36.6	16.3 %
Fixed Income	1,004.3	70.6 %	94.7	42.1 %
Real Estate	5.0	0.3 %	—	—
Cash/Other	63.4	4.5 %	6.7	3.0 %
Total	$ 1,422.8	100.0 %	$ 224.9	100.0 %

	Defined Benefit Pension Assets[1]	December 31, 2021	Postretirement Benefit Plan Assets	December 31, 2021
Asset Class *(in millions)*	Asset Value	% of Total Assets	Asset Value	% of Total Assets
Domestic Equities	$ 324.3	16.4 %	$ 118.6	40.4 %
International Equities	150.9	7.6 %	50.5	17.2 %
Fixed Income	1,382.3	69.7 %	118.8	40.4 %
Real Estate	37.2	1.9 %	—	—
Cash/Other	87.0	4.4 %	5.8	2.0 %
Total	$ 1,981.7	100.0 %	$ 293.7	100.0 %

[1]Total includes accrued dividends and pending trades with brokers.

The categorization of investments into the asset classes in the tables above are based on definitions established by the Committee.

Fair Value Measurements. The following table sets forth, by level within the fair value hierarchy, the pension and other postretirement benefits investment assets at fair value as of December 31, 2022 and 2021. Assets are classified in their entirety based on the observability of inputs used in determining the fair value measurement. There were no investment assets in the pension and other postretirement benefits trusts classified within Level 3 for the years ended December 31, 2022 and 2021.

We use the following valuation techniques to determine fair value. For the year ended December 31, 2022, there were no significant changes to valuation techniques to determine the fair value of our pension and other postretirement benefits' assets.

Level 1 Measurements
Most common and preferred stocks are traded in active markets on national and international securities exchanges and are valued at closing prices on the last business day of each period presented. Cash is stated at cost, which approximates fair value, with the exception of cash held in foreign currencies which fluctuates with changes in the exchange rates. Short-term bills and notes are priced based on quoted market values.

Level 2 Measurements
Most U.S. Government Agency obligations, mortgage/asset-backed securities, and corporate fixed income securities are generally valued by benchmarking model-derived prices to quoted market prices and trade data for identical or comparable securities. To the extent that quoted prices are not available, fair value is determined based on a valuation model that includes inputs such as interest rate yield curves and credit spreads. Securities traded in markets that are not considered active are valued based on quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. Other fixed income includes futures and options which are priced on bid valuation or settlement pricing.

Level 3 Measurements
Investments with unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets and liabilities are classified as level 3 investments.

Not Classified
Commingled funds, private equity limited partnerships and real estate partnerships are not classified within the fair value hierarchy. Instead, these assets are measured at estimated fair value using the net asset value per share of the investments. Commingled funds' underlying assets are principally marketable equity and fixed income securities. Units held in commingled funds are valued at the unit value as reported by the investment managers. Private equity funds invest capital in non-public companies and real estate funds invest in commercial and distressed real estate directly or through related debt instruments. The fair value of these investments is determined by reference to the funds’ underlying assets.

Fair Value Measurements at December 31, 2022:

(in millions)	December 31, 2022	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Pension plan assets:				
Cash	$ 2.5	$ 2.0	$ 0.5	$ —
Equity securities				
International equities	0.5	0.5	—	—
Fixed income securities				
Government	316.3	—	316.3	—
Corporate	407.8	—	407.8	—
Mortgages/ Asset Backed Securities	2.3	—	2.3	—
Other fixed income	1.9	1.9	—	—
Mutual Funds				
U.S. multi-strategy	97.4	97.4	—	—
International equities	29.0	29.0	—	—
Fixed income	0.2	0.2	—	—
Private equity limited partnerships(3)				
U.S. multi-strategy(1)	6.3	—	—	—
International multi-strategy(2)	2.3	—	—	—
Distressed opportunities	0.1	—	—	—
Real estate(3)	5.0	—	—	—
Commingled funds(3)				
Short-term money markets	46.2	—	—	—
U.S. equities	133.7	—	—	—
International equities	89.6	—	—	—
Fixed income	275.9	—	—	—
Pension plan assets subtotal	$ 1,417.0	$ 131.0	$ 726.9	$ —
Other postretirement benefit plan assets:				
Mutual funds				
U.S. multi-strategy	76.2	76.2	—	—
International equities	16.3	16.3	—	—
Fixed income	94.7	94.7	—	—
Commingled funds(3)				
Short-term money markets	17.4	—	—	—
U.S. equities	10.7	—	—	—
International equities	20.3	—	—	—
Other postretirement benefit plan assets subtotal	$ 235.6	$ 187.2	$ —	$ —
Due to brokers, net(4)	(2.0)	—	(2.0)	—
Receivables/payables	(10.7)	—	(10.7)	—
Accrued income/dividends	7.8	7.8	—	—
Total pension and other postretirement benefit plan assets	$ 1,647.7	$ 326.0	$ 714.2	$ —

(1)This class includes limited partnerships/fund of funds that invest in a diverse portfolio of private equity strategies, including buy-outs, growth capital, special situations and secondary markets, primarily inside the United States.
(2)This class includes limited partnerships/fund of funds that invest a in diverse portfolio of private equity strategies, including buy-outs, growth capital, special situations and secondary markets, primarily outside the United States.

(3)This class of investments is measured at fair value using the net asset value per share and has not been classified in the fair value hierarchy.
(4)This class represents pending trades with brokers.

The table below sets forth a summary of unfunded commitments, redemption frequency and redemption notice periods for certain investments that are measured at fair value using the net asset value per share for the year ended December 31, 2022:

(in millions)	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
Commingled Funds				
Short-term money markets	$ 63.6	$ —	Daily	1 day
U.S. equities	144.4	—	Daily	1 day - 5 days
International equities	109.9	—	Monthly	10 days-30 days
Fixed income	275.9	—	Daily	3 days
Private Equity and Real Estate Limited Partnerships[1]	13.7	11.6	N/A	N/A
Total	$ 607.5	$ 11.6		

(1)Private equity and real estate limited partnerships typically call capital over a 3-5 year period and pay out distributions as the underlying investments are liquidated. The typical expected life of these limited partnerships is 0-15 years, and these investments typically cannot be redeemed prior to liquidation.

Fair Value Measurements at December 31, 2021:

(in millions)	December 31, 2021	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Pension plan assets:				
Cash	$ 10.3	$ 9.7	$ 0.6	$ —
Equity securities				
International equities	0.5	0.5	—	—
Fixed income securities				
Government	387.3	—	387.3	—
Corporate	645.9	—	645.9	—
Mutual Funds				
U.S. multi-strategy	128.4	128.4	—	—
International equities	38.7	38.7	—	—
Private equity limited partnerships(3)				
U.S. multi-strategy(1)	10.9	—	—	—
International multi-strategy(2)	4.5	—	—	—
Distressed opportunities	0.1	—	—	—
Real estate(3)	37.2	—	—	—
Commingled funds(3)				
Short-term money markets	55.0	—	—	—
U.S. equities	195.9	—	—	—
International equities	111.7	—	—	—
Fixed income	349.1	—	—	—
Pension plan assets subtotal	$ 1,975.5	$ 177.3	$ 1,033.8	$ —
Other postretirement benefit plan assets:				
Mutual funds				
U.S. multi-strategy	103.8	103.8	—	—
International equities	24.4	24.4	—	—
Fixed income	118.5	118.5	—	—
Commingled funds(3)				
Short-term money markets	5.8	—	—	—
U.S. equities	14.8	—	—	—
International equities	26.1	—	—	—
Other postretirement benefit plan assets subtotal	$ 293.4	$ 246.7	$ —	$ —
Due to brokers, net(4)	(1.8)	—	(1.8)	—
Receivables/payables	0.3	—	0.3	—
Accrued income/dividends	8.0	8.0	—	—
Total pension and other postretirement benefit plan assets	$ 2,275.4	$ 432.0	$ 1,032.3	$ —

(1)This class includes limited partnerships/fund of funds that invest in a diverse portfolio of private equity strategies, including buy-outs, venture capital, growth capital, special situations and secondary markets, primarily inside the United States.
(2)This class includes limited partnerships/fund of funds that invest in diverse portfolio of private equity strategies, including buy-outs, venture capital, growth capital, special situations and secondary markets, primarily outside the United States.
(3)This class of investments is measured at fair value using the net asset value per share and has not been classified in the fair value hierarchy.
(4)This class represents pending trades with brokers.

The table below sets forth a summary of unfunded commitments, redemption frequency and redemption notice periods for certain investments that are measured at fair value using the net asset value per share for the year ended December 31, 2021:

(in millions)	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
Commingled Funds				
Short-term money markets	$ 60.8	$ —	Daily	1 day
U.S. equities	210.7	—	Daily	1 day -5 days
International equities	137.8	—	Monthly	10 days - 30 days
Fixed income	349.1	—	Daily	3 days
Private Equity and Real Estate Limited Partnerships(1)	20.4	12.1	N/A	N/A
Total	$ 778.8	$ 12.1		

(1)Private equity and real estate limited partnerships typically call capital over a 3-5 year period and pay out distributions as the underlying investments are liquidated. The typical expected life of these limited partnerships is 0-15 years, and these investments typically cannot be redeemed prior to liquidation.

Our Pension and Other Postretirement Benefit Plans' Funded Status and Related Disclosure. The following table provides a reconciliation of the plans' funded status and amounts reflected in our Consolidated Balance Sheets at December 31 based on a December 31 measurement date:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2022**	2021	**2022**	2021
Change in projected benefit obligation[1]				
Benefit obligation at beginning of year	**$ 1,852.4**	$ 2,058.4	**$ 556.2**	$ 590.8
Service cost	**27.8**	30.2	**6.5**	6.2
Interest cost	**40.5**	31.4	**12.0**	9.9
Plan participants' contributions	**—**	—	**4.1**	4.2
Plan amendments	**0.2**	—	**2.1**	0.1
Actuarial gain[2]	**(318.7)**	(68.7)	**(89.9)**	(14.8)
Benefits paid	**(174.8)**	(198.9)	**(42.3)**	(40.6)
Estimated benefits paid by incurred subsidy	**—**	—	**0.3**	0.4
Projected benefit obligation at end of year	**$ 1,427.4**	$ 1,852.4	**$ 449.0**	$ 556.2
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 1,981.7**	$ 2,117.7	**$ 293.7**	$ 286.4
Actual return on plan assets	**(386.8)**	58.9	**(51.9)**	23.9
Employer contributions	**2.7**	4.0	**21.3**	19.8
Plan participants' contributions	**—**	—	**4.1**	4.2
Benefits paid	**(174.8)**	(198.9)	**(42.3)**	(40.6)
Fair value of plan assets at end of year	**$ 1,422.8**	$ 1,981.7	**$ 224.9**	$ 293.7
Funded Status at end of year	**$ (4.6)**	$ 129.3	**$ (224.1)**	$ (262.5)
Amounts recognized in the statement of financial position consist of:				
Noncurrent assets	**18.3**	159.3	**—**	—
Current liabilities	**(2.6)**	(2.8)	**(1.0)**	(1.0)
Noncurrent liabilities	**(20.3)**	(27.2)	**(223.1)**	(261.5)
Net amount recognized at end of year[3]	**$ (4.6)**	$ 129.3	**$ (224.1)**	$ (262.5)
Amounts recognized in accumulated other comprehensive income or regulatory asset/liability[4]				
Unrecognized prior service credit	**$ 0.4**	$ 0.3	**$ (3.4)**	$ (7.8)
Unrecognized actuarial loss	**564.2**	438.0	**64.0**	88.5
Net amount recognized at end of year	**$ 564.6**	$ 438.3	**$ 60.6**	$ 80.7

[1]The change in benefit obligation for Pension Benefits represents the change in Projected Benefit Obligation while the change in benefit obligation for Other Postretirement Benefits represents the change in accumulated postretirement benefit obligation.
[2]The pension actuarial gain was primarily driven by the increase in discount rate. The postretirement benefit gain was also primarily driven by an increase in discount rates.
[3]We recognize our Consolidated Balance Sheets underfunded and overfunded status of our various defined benefit postretirement plans, measured as the difference between the fair value of the plan assets and the benefit obligation.
[4]We determined that for certain rate-regulated subsidiaries the future recovery of pension and other postretirement benefits costs is probable. These rate-regulated subsidiaries recorded regulatory assets and liabilities of $607.5 million and zero, respectively, as of December 31, 2022, and $512.1 million and zero, respectively, as of December 31, 2021 that would otherwise have been recorded to accumulated other comprehensive loss.

Our accumulated benefit obligation for our pension plans was $1,416.8 million and $1,834.4 million as of December 31, 2022 and 2021, respectively. The accumulated benefit obligation at each date is the actuarial present value of benefits attributed by the pension benefit formula to employee service rendered prior to that date and based on current and past compensation levels. The accumulated benefit obligation differs from the projected benefit obligation disclosed in the table above in that it includes no assumptions about future compensation levels.

We are required to reflect the funded status of our pension and postretirement benefit plans on the Consolidated Balance Sheet. The funded status of the plans is measured as the difference between the plan assets' fair value and the projected benefit obligation. We present the noncurrent aggregate of all underfunded plans within "Accrued liability for postretirement and postemployment benefits." The portion of the amount by which the actuarial present value of benefits included in the projected benefit obligation exceeds the fair value of plan assets, payable in the next 12 months, is reflected in "Accrued compensation and other benefits." We present the aggregate of all overfunded plans within "Deferred charges and other."

Information for pension plans with a projected benefit obligation in excess of plan assets:

	December 31,	
	2022	2021
Accumulated Benefit Obligation	**$ 22.9**	$ 30.0
Funded Status		
Projected Benefit Obligation	**22.9**	30.0
Funded Status of Underfunded Pension Plans at End of Year[1]	**$ (22.9)**	$ (30.0)

[1]As of December 31, 2022 and 2021, only our nonqualified plans were underfunded. These plans have no assets as they are not funded until benefits are paid.

Information for pension plans with plan assets in excess of the projected benefit obligation:

	December 31,	
	2022	2021
Accumulated Benefit Obligation	**$ 1,393.8**	$ 1,804.3
Funded Status		
Projected Benefit Obligation	**1,404.5**	1,822.4
Fair Value of Plan Assets	**1,422.8**	1,981.7
Funded Status of Overfunded Pension Plans at End of Year	**$ 18.3**	$ 159.3

Our pension plans were underfunded, in aggregate, by $4.6 million at December 31, 2022 compared to being overfunded by $129.3 million at December 31, 2021. The decline in the funded status was primarily due to unfavorable asset returns offset by an increase in discount rates. We contributed $2.7 million and $4.0 million to our pension plans in 2022 and 2021, respectively.

Our other postretirement benefit plans were underfunded by $224.1 million at December 31, 2022 compared to being underfunded by $262.5 million at December 31, 2021. The improvement in funded status was primarily due to increased discount rates offset by unfavorable asset returns. We contributed $21.3 million and $19.8 million to our other postretirement benefit plans in 2022 and 2021, respectively.

In 2022 and 2021, some of our qualified pension plans paid lump sum payouts in excess of the respective plan's service cost plus interest cost, thereby meeting the requirement for settlement accounting. We recorded settlement charges of $12.4 million and $11.4 million in 2022 and 2021, respectively. Net periodic pension benefit cost increased by $5.7 million and $4.0 million in 2022 and 2021, respectively, as the result of the remeasurement.

The following table provides the key assumptions that were used to calculate the pension and other postretirement benefits obligations for our various plans as of December 31:

	Pension Benefits		Other Postretirement Benefits	
	2022	2021	**2022**	2021
Weighted-average assumptions to Determine Benefit Obligation				
Discount Rate	**5.14 %**	2.76 %	**5.17 %**	2.85 %
Rate of Compensation Increases	**4.00 %**	4.00 %	**N/A**	N/A
Interest Crediting Rates	**4.00 %**	4.00 %	**N/A**	N/A
Health Care Trend Rates				
Trend for Next Year	**N/A**	N/A	**6.69 %**	6.20 %
Ultimate Trend	**N/A**	N/A	**4.75 %**	4.50 %
Year Ultimate Trend Reached	**N/A**	N/A	**2032**	2030

We expect to make contributions of approximately $2.6 million to our pension plans and approximately $23.7 million to our postretirement medical and life plans in 2023.

The following table provides benefits expected to be paid in each of the next five fiscal years, and in the aggregate for the five fiscal years thereafter. The expected benefits are estimated based on the same assumptions used to measure our benefit obligation at the end of the year and include benefits attributable to the estimated future service of employees:

(in millions)	Pension Benefits	Other Postretirement Benefits	Federal Subsidy Receipts
Year(s)			
2023	$ 150.5	$ 38.9	$ 0.4
2024	145.2	38.5	0.2
2025	141.2	37.8	0.2
2026	133.8	36.9	0.2
2027	128.1	36.4	0.2
2028-2032	563.2	172.0	0.9

The following table provides the components of the plans' actuarially determined net periodic benefits cost for each of the three years ended December 31, 2022, 2021 and 2020:

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2022**	2021	2020	**2022**	2021	2020
Components of Net Periodic Benefit (Income) Cost[(1)]						
Service cost	**$ 27.8**	$ 30.2	$ 32.0	**$ 6.5**	$ 6.2	$ 6.6
Interest cost	**40.5**	31.4	51.6	**12.0**	9.9	15.4
Expected return on assets	**(90.8)**	(101.6)	(111.6)	**(16.2)**	(15.3)	(14.4)
Amortization of prior service cost (credit)	**0.1**	0.1	0.7	**(2.2)**	(2.2)	(2.1)
Recognized actuarial loss	**20.3**	21.7	33.8	**2.6**	4.6	4.9
Settlement/curtailment loss	**12.4**	11.4	10.5	**—**	—	1.5
Total Net Periodic Benefits (Income) Cost	**$ 10.3**	$ (6.8)	$ 17.0	**$ 2.7**	$ 3.2	$ 11.9

(1) Service cost is presented in "Operation and maintenance" on the Statements of Consolidated Income (Loss). Non-service cost components are presented within "Other, net."

The following table provides the key assumptions that were used to calculate the net periodic benefits cost for our various plans:

	Pension Benefits			Other Postretirement Benefits		
	2022	2021	2020	**2022**	2021	2020
Weighted-average Assumptions to Determine Net Periodic Benefit Cost						
Discount rate - service cost	**3.08 %**	2.81 %	3.39 %	**3.21 %**	3.00 %	3.52 %
Discount rate - interest cost	**2.11 %**	1.57 %	2.65 %	**2.24 %**	1.73 %	2.76 %
Expected Long-Term Rate of Return on Plan Assets	**4.80 %**	5.20 %	5.70 %	**5.72 %**	5.50 %	5.67 %
Rate of Compensation Increases	**4.00 %**	4.00 %	4.00 %	**N/A**	N/A	N/A
Interest Crediting Rates	**4.00 %**	4.00 %	4.00 %	**N/A**	N/A	N/A

We assumed a 4.80% and 5.72% rate of return on pension and other postretirement plan assets, respectively, for our calculation of 2022 pension benefits and other postretirement benefits costs. These rates were primarily based on asset mix and historical rates of return and were adjusted in 2022 due to anticipated changes in asset allocation and projected market returns.

The following table provides other changes in plan assets and projected benefit obligations recognized in other comprehensive income or regulatory asset or liability:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2022**	2021	**2022**	2021
Other Changes in Plan Assets and Projected Benefit Obligations Recognized in Other Comprehensive Income or Regulatory Asset or Liability				
Net prior service cost	**$ 0.2**	$ —	**$ 2.1**	$ 0.1
Net actuarial loss (gain)	**158.9**	(26.0)	**(21.8)**	(23.3)
Settlements/curtailments	**(12.4)**	(11.4)	**—**	—
Less: amortization of prior service cost	**(0.1)**	(0.1)	**2.2**	2.2
Less: amortization of net actuarial loss	**(20.3)**	(21.7)	**(2.6)**	(4.6)
Total Recognized in Other Comprehensive Income or Regulatory Asset or Liability	**$ 126.3**	$ (59.2)	**$ (20.1)**	$ (25.6)
Amount Recognized in Net Periodic Benefits Cost and Other Comprehensive Income or Regulatory Asset or Liability	**$ 136.6**	$ (66.0)	**$ (17.4)**	$ (22.4)

13. Equity

Holders of shares of our common stock are entitled to receive dividends when, as, and if declared by the Board out of funds legally available. The policy of the Board has been to declare cash dividends on a quarterly basis payable on or about the 20th day of February, May, August and November. We have certain debt covenants that could potentially limit the amount of dividends we could pay in order to maintain compliance with these covenants. Refer to Note 15, "Long-Term Debt," for more information. As of December 31, 2022, these covenants did not restrict the amount of dividends that were available to be paid.

Dividends paid to preferred shareholders vary based on the series of preferred stock owned. Holders of our shares of common stock are subject to the prior dividend rights of holders of our preferred stock or the depositary shares representing such preferred stock outstanding, and if full dividends have not been declared and paid on all outstanding shares of preferred stock in any dividend period, no dividend may be declared or paid or set aside for payment on our common stock.

Common and preferred stock activity for 2022, 2021 and 2020 is described further below.

ATM Program. On November 1, 2018, we entered into five separate equity distribution agreements pursuant to which we were able to sell up to an aggregate of $500.0 million of our common stock. Four of these agreements were then amended on August 1, 2019 and one was terminated, pursuant to which we were able to sell up to an aggregate of $434.4 million of our common stock. These equity distribution agreements impacting fiscal year 2020 expired on December 31, 2020.

On February 22, 2021, we entered into six separate equity distribution agreements pursuant to which we are able to sell up to an aggregate of $750.0 million of our common stock.

On August 9, 2021, under the ATM program, we executed a forward sale agreement, which allowed us to issue a fixed number of shares at a price to be settled in the future. From August 9, 2021 to September 1, 2021, the forward purchaser under our forward sale agreement borrowed 5,941,598 shares from third parties, which the forward purchaser sold, through its affiliated agent, at a weighted average price of $25.25 per share. On November 16, 2022, the forward sale agreement was settled for $23.90 per share, resulting in $142.0 million of net proceeds.

As of December 31, 2022, the ATM program had approximately $300.0 million of equity available for issuance. The program expires on December 31, 2023.

The following table summarizes our activity under the ATM program.

Year Ending December 31,	**2022**	2021	2020
Number of shares issued	**5,941,598**	12,525,215	8,459,430
Average price per share	**$ 25.25**	$ 23.95	$ 23.60
Proceeds, net of fees (*in millions*)	**$ 141.9**	$ 288.1	$ 196.5

Preferred Stock. On June 11, 2018, we completed the sale of 400,000 shares of 5.650% Series A Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock (the "Series A Preferred Stock") at a price of $1,000 per share. The transaction resulted in $400.0 million of gross proceeds or $393.9 million of net proceeds, after deducting commissions and sale expenses. The Series A Preferred Stock was issued in a private placement pursuant to SEC Rule 144A. On December 13, 2018, we filed a registration statement with the SEC enabling holders to exchange their unregistered shares of Series A Preferred Stock for publicly registered shares with substantially identical terms.

Dividends on the Series A Preferred Stock accrue and are cumulative from the date the shares of Series A Preferred Stock were originally issued to, but not including, June 15, 2023 at a rate of 5.650% per annum of the $1,000 liquidation preference per share. On and after June 15, 2023, dividends on the Series A Preferred Stock will accumulate for each five year period at a percentage of the $1,000 liquidation preference equal to the five-year U.S. Treasury Rate plus (i) in respect of each five year period commencing on or after June 15, 2023 but before June 15, 2043, a spread of 2.843% (the “Initial Margin”), and (ii) in respect of each five year period commencing on or after June 15, 2043, the Initial Margin plus 1.000%. The Series A Preferred Stock may be redeemed by us at our option on June 15, 2023, or on each date falling on the fifth anniversary thereafter, or in connection with a ratings event (as defined in the Certificate of Designation of the Series A Preferred Stock).

As of December 31, 2022 and 2021, Series A Preferred Stock had $1.0 million of cumulative preferred dividends in arrears, or $2.51 per share.

Holders of Series A Preferred Stock generally have no voting rights, except for limited voting rights with respect to (i) potential amendments to our certificate of incorporation that would have a material adverse effect on the existing preferences, rights, powers or duties of the Series A Preferred Stock, (ii) the creation or issuance of any security ranking on a parity with the Series A Preferred Stock if the cumulative dividends payable on then outstanding Series A Preferred Stock are in arrears, or (iii) the creation or issuance of any security ranking senior to the Series A Preferred Stock. The Series A Preferred Stock does not have a stated maturity and is not subject to mandatory redemption or any sinking fund. The Series A Preferred Stock will remain outstanding indefinitely unless repurchased or redeemed by us. Any such redemption would be effected only out of funds legally available for such purposes and will be subject to compliance with the provisions of our outstanding indebtedness.

On December 5, 2018, we completed the sale of 20,000,000 depositary shares with an aggregate liquidation preference of $500,000,000 under the Company’s registration statement on Form S-3. Each depositary share represents 1/1,000th ownership interest in a share of our 6.500% Series B Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock, liquidation preference $25,000 per share (equivalent to $25 per depositary share) (the “Series B Preferred Stock"). The transaction resulted in $500.0 million of gross proceeds or $486.1 million of net proceeds, after deducting commissions and sale expenses.

Dividends on the Series B Preferred Stock accrue and are cumulative from the date the shares of Series B Preferred Stock were originally issued to, but not including, March 15, 2024 at a rate of 6.500% per annum of the $25,000 liquidation preference per share. On and after March 15, 2024, dividends on the Series B Preferred Stock will accumulate for each five year period at a percentage of the $25,000 liquidation preference equal to the five-year U.S. Treasury Rate plus (i) in respect of each five year period commencing on or after March 15, 2024 but before March 15, 2044, a spread of 3.632% (the "Initial Margin"), and (ii) in respect of each five year period commencing on or after March 15, 2044, the Initial Margin plus 1.000%. The Series B Preferred Stock may be redeemed by us at our option on March 15, 2024, or on each date falling on the fifth anniversary thereafter, or in connection with a ratings event (as defined in the Certificate of Designation of the Series B Preferred Stock).

As of December 31, 2022 and 2021, Series B Preferred Stock had $1.4 million of cumulative preferred dividends in arrears, or $72.23 per share.

In addition, 20,000 shares of Series B–1 Preferred Stock, par value $0.01 per share, were outstanding as of December 31, 2022. Holders of Series B–1 Preferred Stock are not entitled to receive dividend payments and have no conversion rights. The Series B–1 Preferred Stock is paired with the Series B Preferred Stock and may not be transferred, redeemed or repurchased except in connection with the simultaneous transfer, redemption or repurchase of the underlying Series B Preferred Stock.

Holders of Series B Preferred Stock generally have no voting rights, except for limited voting rights with respect to (i) potential amendments to our certificate of incorporation that would have a material adverse effect on the existing preferences, rights, powers or duties of the Series B Preferred Stock, (ii) the creation or issuance of any security ranking on a parity with the Series B Preferred Stock if the cumulative dividends payable on then outstanding Series B Preferred Stock are in arrears, or (iii) the creation or issuance of any security ranking senior to the Series B Preferred Stock. In addition, if and whenever dividends on any shares of Series B Preferred Stock shall not have been declared and paid for at least six dividend periods, whether or not consecutive, the number of directors then constituting our Board of Directors shall automatically be increased by two until all accumulated and unpaid dividends on the Series B Preferred Stock shall have been paid in full, and the holders of Series B-1 Preferred Stock, voting as a class together with the holders of any outstanding securities ranking on a parity with the Series B-1 Preferred Stock and having like voting rights that are exercisable at the time and entitled to vote thereon, shall be entitled to elect the two additional directors. The Series B Preferred Stock does not have a stated maturity and is not subject to mandatory redemption or any sinking fund. The Series B Preferred Stock will remain outstanding indefinitely unless repurchased or redeemed by us. Any such redemption would be effected only out of funds legally available for such purposes and will be subject to compliance with the provisions of our outstanding indebtedness.

The following table summarizes preferred stock by outstanding series of shares:

			Year ended December 31,			December 31,	December 31,
			2022	2021	2020	2022	2021
(in millions except shares and per share amounts)	Liquidation Preference Per Share	Shares	Dividends Declared Per Share			Outstanding	
5.650% Series A	$ 1,000.00	400,000	$ 56.50	$ 56.50	$ 56.50	$ 393.9	$ 393.9
6.500% Series B	25,000.00	20,000	1,625.00	1,625.00	1,625.00	486.1	486.1
Series C[(1)]	$ 1,000.00	862,500	—	—	—	$ 666.5	$ 666.5

[(1)] The Series C Mandatory Convertible Preferred Stock initially will not bear any dividends. We recorded the initial present value of the purchase contract payments as a liability with a corresponding reduction to preferred stock.

Equity Units. On April 19, 2021, we completed the sale of 8.625 million Equity Units, initially consisting of Corporate Units, each with a stated amount of $100. The offering generated net proceeds of $835.5 million, after underwriting and issuance expenses. Each Corporate Unit consists of a forward contract to purchase shares of our common stock in the future and a 1/10th, or 10%, undivided beneficial ownership interest in one share of Series C Mandatory Convertible Preferred Stock, par value $0.01 per share, with a liquidation preference of $1,000 per share.

Selected information about the Equity Units is presented below:

(in millions except contract rate)	Issuance Date	Units Issued	Total Net Proceeds[1]	Purchase Contract Annual Rate	Purchase Contract Liability
Equity Units	April 19, 2021	8.625	$ 835.5	7.75 %	$ 168.8

[1]Issuance costs of $27.0 million were recorded on a relative fair value basis as a reduction to preferred stock of $22.5 million and a reduction to the purchase contract liability of $4.5 million.

The purchase contract obligates holders to purchase shares of our common stock on December 1, 2023, subject to early settlement in certain situations. The purchase price paid under the purchase contract is $100 and the number of shares to be purchased will be determined under a settlement rate formula based on the volume-weighted average share price of our common stock near the settlement date, subject to a maximum settlement rate. The Series C Mandatory Convertible Preferred Stock will initially be pledged upon issuance as collateral to secure the purchase of common stock under the related purchase contracts.

The Series C Mandatory Convertible Preferred Stock is expected to be remarketed prior to December 1, 2023, and each share, unless previously converted, will automatically convert to common stock based on a conversion rate on the mandatory conversion date, which is expected to be on or about March 1, 2024. The conversion rate will be determined based on the volume-weighted average share price of our common stock near the conversion date, subject to a minimum and maximum conversion rate. Prior to December 1, 2023, the Series C Mandatory Convertible Preferred Stock will not bear any dividends and the liquidation preference will not accrete. Following a successful remarketing, dividends may become payable on the Series C Mandatory Convertible Preferred Stock and/or the minimum conversion rate of the Series C Mandatory Convertible Preferred Stock may be increased. If no successful remarketing of the Series C Mandatory Convertible Preferred Stock has previously occurred, effective as of December 1, 2023, the conversion rate will be zero, no shares of our common stock will be delivered upon automatic conversion and each share of Series C Mandatory Convertible Preferred Stock will be automatically transferred to us on the mandatory conversion date without any payment of cash or shares of our common stock thereon. In the event of such a remarketing failure, any shares of Series C Mandatory Convertible Preferred Stock held as part of Corporate Units will be automatically delivered to us on December 1, 2023 in full satisfaction of the relevant holder's obligation under the related purchase contracts.

We will pay quarterly contract adjustment payments at the rate of 7.75% per year on the stated amount of $100 per Equity Unit. The contract adjustment payments are payable in cash, shares of our common stock or a combination thereof, at our election. The payment of contract adjustment payments may also be deferred until the purchase contract settlement date, December 1, 2023, at our election. If we exercise our option to defer the payment of contract adjustment payments, then until the deferred contract adjustment payments have been paid, we will not declare or pay any dividends on, or make any distributions on, or redeem, purchase or acquire, or make a liquidation payment with respect to, any shares of our capital stock; make any payment of principal of, or interest or premium, if any, on, or repay, repurchase or redeem any of our debt securities that rank on parity with, or junior to, the contract adjustment payments; or make any guarantee payments under any guarantee by us of securities of any of our subsidiaries if our guarantee ranks on parity with, or junior to, the contract adjustment payments. As of December 31, 2022, no contract adjustment payments have been deferred with quarterly cash payments being remitted to the holders. As of December 31, 2022 and December 31, 2021 the purchase contract liability was $65.0 million and $129.4 million, respectively. Purchase contract payments are recorded against this liability. Accretion of the purchase contract liability is recorded as interest expense. Cash payments of $66.8 million and $41.2 million were made during the years ended December 31, 2022 and 2021, respectively.

The Series C Mandatory Convertible Preferred Stock and forward purchase contracts are legally detachable and separately exercisable, however, due to the economic linkage between the forward purchase contract and the Series C Mandatory Convertible Preferred Stock, we have concluded that the ability to separate the Corporate Units is non-substantive. Accordingly, we are accounting for the Corporate Units as a single unit of account. We recorded the initial present value of the purchase contract payments as a liability with a corresponding reduction to preferred stock. This liability is included in "Other accruals"go on the Consolidated Balance Sheets.

Refer to Note 5, "Earnings Per Share," for additional information regarding our treatment of the Equity Units for diluted EPS. Under the terms of the Equity Units, assuming no anti-dilution or other adjustments such as a fundamental change, the maximum number of shares of common stock we will issue under the purchase contracts is 35.2 million and maximum number of shares of common stock we will issue under the Series C Mandatory Convertible Preferred Stock is 35.2 million. Had we settled the remaining purchase contract payment balance in shares at December 31, 2022, we would have issued approximately 2.5 million shares.

Noncontrolling Interest in Consolidated Subsidiaries. As of December 31, 2022 and 2021, NIPSCO and tax equity partners have completed their cash contributions into the Indiana Crossroads Wind and Rosewater JVs and made initial cash contributions into the Indiana Crossroads Solar JV. Earnings, tax attributes and cash flows are allocated to both NIPSCO and the respective tax equity partners in varying percentages by category and over the life of the partnership. The tax equity partner's contributions, net of these allocations, is represented as a noncontrolling interest within total equity on the Consolidated Balance Sheets. Refer to Note 4, "Variable Interest Entities," for more information.

14. Share-Based Compensation

Prior to May 19, 2020, we issued share-based compensation to employees and non-employee directors under the NiSource Inc. 2010 Omnibus Plan ("2010 Omnibus Plan"), which was most recently approved by stockholders at the Annual Meeting of Stockholders held on May 12, 2015. The 2010 Omnibus Plan provided for awards to employees and non-employee directors of incentive and nonqualified stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock-based awards and superseded the Director Stock Incentive Plan (“Director Plan”) with respect to grants made after the effective date of the 2010 Omnibus Plan.

The stockholders approved and adopted the NiSource Inc. 2020 Omnibus Incentive Plan ("2020 Omnibus Plan") at the Annual Meeting of Stockholders held on May 19, 2020. The 2020 Omnibus Plan provides for awards to employees and non-employee directors of incentive and nonqualified stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock-based awards and supersedes the 2010 Omnibus Plan with respect to grants made after the effective date of the 2020 Omnibus Plan.

The 2020 Omnibus Plan provides that the number of shares of common stock of NiSource available for awards is 10,000,000 plus the number of shares subject to outstanding awards that expire or terminate for any reason that were granted under the 2020 Omnibus Plan, the 2010 Omnibus Plan or any other equity plan under which awards were outstanding as of May 19, 2020. At December 31, 2022, there were 8,704,201 shares available for future awards under the 2020 Omnibus Plan.

We recognized stock-based employee compensation expense of $19.0 million, $16.7 million and $13.5 million, during 2022, 2021 and 2020, respectively, as well as related tax benefits of $3.6 million, $4.0 million and $3.3 million, respectively. We recognized related excess tax benefit from the distribution of vested share-based employee compensation of $0.4 million in 2022 and 2021, and excess tax expense of $0.4 million in 2020.

As of December 31, 2022, the total remaining unrecognized compensation cost related to non-vested awards amounted to $27.0 million, which will be amortized over the weighted-average remaining requisite service period of 1.8 years.

Restricted Stock Units and Restricted Stock. We granted 477,292, 285,755, and 235,100 restricted stock units and shares of restricted stock to employees, subject to service conditions in 2022, 2021, and 2020, respectively. The total grant date fair value of the restricted stock units and shares of restricted stock during 2022, 2021, and 2020, respectively, was $12.5 million, $5.7 million, and $6.1 million based on the average market price of our common stock at the date of each grant less the present value of any dividends not received during the vesting period, which will be expensed over the vesting period which is generally three years. As of December 31, 2022, 444,646, 218,465, and 135,404 non-vested restricted stock units and shares of restricted stock granted in 2022, 2021, and 2020, respectively, were outstanding.

If an employee terminates employment before the service conditions lapse under the 2020, 2021 or 2022 awards due to (1) retirement or disability (as defined in the award agreement), or (2) death, the service conditions will lapse on the date of such termination with respect to a pro rata portion of the restricted stock units and shares of restricted stock based upon the percentage of the service period satisfied between the grant date and the date of the termination of employment. In the event of a change in control (as defined in the award agreement), all unvested shares of restricted stock and restricted stock units awarded will immediately vest upon termination of employment occurring in connection with a change in control. Termination due to any other reason will result in all unvested shares of restricted stock and restricted stock units awarded being forfeited effective on the employee’s date of termination.

A summary of our restricted stock unit award transactions for the year ended December 31, 2022 is as follows:

(shares)	Restricted Stock Units	Weighted Average Award Date Fair Value Per Unit ($)
Non-vested at December 31, 2021	572,154	22.72
Granted	477,292	26.29
Forfeited	(133,367)	23.48
Vested	(117,564)	24.44
Non-vested at December 31, 2022	**798,515**	**24.48**

Employee Performance Shares. We granted 566,086 performance shares subject to service, performance and/or market-based vesting conditions in 2022. The performance conditions for these shares are based on the achievement of one non-GAAP financial measure, and/or achievement of relative total shareholder return, outlined below. The number of shares that are eligible to vest based on these performance conditions will be adjusted based on performance of the magnifier framework for 2022 awards, outlined below. The operational magnifier framework for 2022 performance shares consists of three areas of focus, including safety, environment, and DE&I, representing 20%, 10% and 10%, respectively.

The financial measure is cumulative net operating earnings per share ("NOEPS"), which we define as income from continuing operations adjusted for certain items. Relative total shareholder return, a market-based vesting condition, which we define as the annualized growth in dividends and share price of a share of our common stock (calculated using a 20 trading day average of our closing price over the performance period, approximately) compared to the total shareholder return of a predetermined peer group of companies. A relative shareholder return result within the first quartile will result in an increase in the NOEPS shares of 25%, while a relative shareholder return result within the fourth quartile will result in a decrease of 25%. A Monte Carlo analysis was used to value the portion of these awards dependent on the market-based vesting condition. The grant date fair value of the NOEPS shares is based on the closing stock price of our common stock at the date of each grant, which will be expensed over the requisite service period of three years. See table below for further details on these awards.

In 2021, we granted 973,885 performance shares subject to service, performance and/or market-based vesting conditions. With respect to 390,941 performance shares granted, the performance conditions are based on the achievement of relative total shareholder return. The number of shares that are eligible to vest based on the Company's relative total shareholder return performance will be adjusted based on a performance magnifier related to safety. A Monte Carlo analysis was used to value the portion of these awards dependent on the market-based vesting condition. The grant date fair value of the NOEPS shares is based on the closing stock price of our common stock at the date of each grant, which will be expensed over the requisite service period of three years. See table below for further details on these awards.

With respect to the remaining 582,944 performance shares granted in 2021, the performance conditions are based on the achievement of one non-GAAP financial measure, and/or achievement of relative total shareholder return. The number of shares that are eligible to vest based on these performance conditions will be adjusted based on performance of the magnifier framework for 2021 awards. The operational magnifier framework for 2021 performance shares consists of three areas of focus including safety, environment, and DE&I, representing 20%, 10% and 10%, respectively.

We granted 528,729 performance shares subject to service, performance and market-based vesting conditions in 2020. The performance conditions are based on the achievement of one non-GAAP financial measure, relative total shareholder return and additional operational measures as outlined below.

If a threshold level of cumulative NOEPS financial performance is achieved, additional operational measures, which we refer to as the customer value framework and which consists of equally weighted areas of focus, apply. Each area of focus represents an equal portion of the customer value framework shares, and the targets for all areas of focus must be met for the customer value framework shares to vest at 100%. The grant date fair value of the customer value framework shares is based on the average market price of our common stock on the grant date of each award less the present value of dividends not received during the vesting period, which will be expensed over the requisite service period of three years for those customer value framework shares that are granted. See table below for further details on these awards.

For the 2020 awards, the customer value framework consists of four equally weighted areas of focus including safety, customer satisfaction, culture and environmental, each representing 25% of the customer value framework shares.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

The following table presents details of the performance awards described above.

Award Year	Service Conditions Lapse date	Performance Period	Award Conditions	Shares outstanding at 12/31/2022 *(shares)*	Grant Date Fair Value *(in millions)*
2022	02/28/25	01/01/2022-12/31/2024	Non-GAAP Financial Measure	245,445	$ 7.4
			Relative Total Shareholder Return	245,445	$ 10.6
2021	02/28/24	01/01/2021-12/31/2023	Non-GAAP Financial Measure	192,119	$ 6.5
			Relative Total Shareholder Return	192,119	$ 6.7
			Relative Total Shareholder Return	88,541	$ 3.2
	02/28/23	01/01/2021-12/31/2022	Relative Total Shareholder Return	179,703	$ 4.8
2020	02/28/23	01/01/2020-12/31/2022	Non-GAAP Financial Measure	294,424	$ 11.7
			Operational Measures	67,943	$ 2.6

A summary of our performance award transactions for the year ended December 31, 2022 is as follows:

(shares)	Performance Awards	Weighted Average Grant Date Fair Value Per Unit ($)
Non-vested at December 31, 2021	1,798,151	23.78
Granted	566,086	31.65
Forfeited	(427,607)	24.34
Vested	(430,890)	25.44
Non-vested at December 31, 2022	**1,505,740**	**26.10**

Non-employee Director Awards. As of May 19, 2020, awards to non-employee directors may be made only under the 2020 Omnibus Plan. Currently, restricted stock units are granted annually to non-employee directors, subject to a non-employee director's election to defer receipt of such restricted stock unit award. The non-employee director's annual award of restricted stock units vest on the first anniversary of the grant date subject to special pro-rata vesting rules in the event of retirement or disability (as defined in the award agreement), or death. The vested restricted stock units are payable as soon as practicable following vesting except as otherwise provided pursuant to the non-employee director's deferral election. Certain restricted stock units remain outstanding from the 2010 Omnibus Plan and the Director Plan. All such awards are fully vested and shall be distributed to the directors upon their separation from the Board.

As of December 31, 2022, 228,604 restricted stock units are outstanding to non-employee directors under either the 2020 Omnibus Plan, the 2010 Omnibus Plan or the Director Plan. Of this amount, 63,215 restricted stock units are unvested and expected to vest.

401(k) Match, Profit Sharing and Company Contribution. Eligible salaried employees hired after January 1, 2010 and hourly and union employees hired after January 1, 2013 receive a non-elective company contribution of 3% of eligible pay payable in cash or shares of NiSource common stock. We also have a voluntary 401(k) savings plan covering eligible union and nonunion employees that allows for periodic discretionary matches as a percentage of each participant's contributions payable in cash or shares. Further, we have a retirement savings plan that provides for discretionary profit sharing contributions to eligible employees. For the years ended December 31, 2022, 2021 and 2020, we recognized 401(k) match, profit sharing and non-elective contribution expense of $39.1 million, $39.1 million and $37.8 million, respectively.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

15. Long-Term Debt

Our long-term debt as of December 31, 2022 and 2021 is as follows:

Long-term debt type	Maturity as of December 31, 2022	Weighted average interest rate (%)	Outstanding balance as of December 31, *(in millions)* 2022	2021
Senior notes:				
NiSource	August 2025	0.95 %	**$1,250.0**	1,250.0
NiSource	May 2027	3.49 %	**1,000.0**	1,000.0
NiSource	December 2027	6.78 %	**3.0**	3.0
NiSource	September 2029	2.95 %	**750.0**	750.0
NiSource	May 2030	3.60 %	**1,000.0**	1,000.0
NiSource	February 2031	1.70 %	**750.0**	750.0
NiSource	December 2040	6.25 %	**152.6**	152.6
NiSource	June 2041	5.95 %	**347.4**	347.4
NiSource	February 2042	5.80 %	**250.0**	250.0
NiSource	February 2043	5.25 %	**500.0**	500.0
NiSource	February 2044	4.80 %	**750.0**	750.0
NiSource	February 2045	5.65 %	**500.0**	500.0
NiSource	May 2047	4.38 %	**1,000.0**	1,000.0
NiSource	March 2048	3.95 %	**750.0**	750.0
NiSource	June 2052	5.00 %	**350.0**	$ —
Total senior notes			**$9,353.0**	$9,003.0
Medium term notes:				
NiSource	May 2027	7.99 %	**$ 29.0**	$ 49.0
NIPSCO	June 2027 to August 2027	7.64 %	**58.0**	68.0
Columbia of Massachusetts	December 2025 to February 2028	6.37 %	**15.0**	15.0
Total medium term notes			**$ 102.0**	$ 132.0
Finance leases:				
NiSource Corporate Services	December 2022 to December 2026	2.34 %	**$ 48.6**	51.4
NIPSCO	December 2027 to November 2035	1.87 %	**16.5**	18.7
Columbia of Ohio	December 2025 to March 2044	6.15 %	**83.5**	87.8
Columbia of Virginia	July 2029 to November 2039	6.26 %	**17.0**	17.7
Columbia of Kentucky	May 2027	3.79 %	**0.2**	0.2
Columbia of Pennsylvania	July 2027 to May 2035	6.28 %	**8.9**	9.8
Total finance leases			**$ 174.7**	185.6
Unamortized issuance costs and discounts			**$ (76.1)**	$ (79.1)
Total Long-Term Debt			**$9,553.6**	$9,241.5

Details of our 2022 long-term debt related activity are summarized below:

- On April 1, 2022, we repaid $20.0 million of 7.99% medium term notes at maturity.
- On June 10, 2022, we completed the issuance and sale of $350.0 million of 5.00% senior unsecured notes maturing in 2052, which resulted in approximately $344.6 million of net proceeds after discount and debt issuance costs.
- On August 30, 2022, NIPSCO repaid $10.0 million of 7.40% medium term notes at maturity.

There was no long-term debt activity during 2021.

See Note 19, "Other Commitments and Contingencies - A. Contractual Obligations," for the outstanding long-term debt maturities at December 31, 2022.

Unamortized debt expense, premium and discount on long-term debt applicable to outstanding bonds are being amortized over the life of such bonds.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

We are subject to a financial covenant under our revolving credit facility and term credit agreement which requires us to maintain a debt to capitalization ratio that does not exceed 70%. As of December 31, 2022, the ratio was 58.9%.

We are also subject to certain other non-financial covenants under the revolving credit facility. Such covenants include a limitation on the creation or existence of new liens on our assets, generally exempting liens on utility assets, purchase money security interests, preexisting security interests and an additional subset of assets equal to $200 million. An asset sale covenant generally restricts the sale, conveyance, lease, transfer or other disposition of our assets to those dispositions that are for a price not materially less than fair market of such assets, that would not materially impair our ability to perform obligations under the revolving credit facility, and that together with all other such dispositions, would not have a material adverse effect. The covenant also restricts dispositions to no more than 15% of our consolidated total assets on December 31, 2020. The revolving credit facility also includes a cross-default provision, which triggers an event of default under the credit facility in the event of an uncured payment default relating to any indebtedness of us or any of our subsidiaries in a principal amount of $75.0 million or more.

Our indentures generally do not contain any financial maintenance covenants. However, our indentures are generally subject to cross-default provisions ranging from uncured payment defaults of $5 million to $50 million, and limitations on the incurrence of liens on our assets, generally exempting liens on utility assets, purchase money security interests, preexisting security interests and an additional subset of assets capped at 10% of our consolidated net tangible assets.

16. Short-Term Borrowings

We generate short-term borrowings from our revolving credit facility, commercial paper program, accounts receivable transfer programs, and term credit agreement. Each of these borrowing sources is described further below.

Revolving Credit Facility. We maintain a revolving credit facility to fund ongoing working capital requirements, including the provision of liquidity support for our commercial paper program, provide for issuance of letters of credit, and also for general corporate purposes. Our revolving credit facility has a program limit of $1.85 billion and is comprised of a syndicate of banks. On February 18, 2022, we extended the termination date of our revolving credit facility to February 18, 2027. At December 31, 2022 and 2021, we had no outstanding borrowings under this facility.

Commercial Paper Program. Our commercial paper program has a program limit of up to $1.5 billion. We had $415.0 million and $560.0 million of commercial paper outstanding with weighted-average interest rates of 4.60% and 0.24% as of December 31, 2022 and 2021, respectively.

Accounts Receivable Transfer Programs. Columbia of Ohio, NIPSCO, and Columbia of Pennsylvania each maintain a receivables agreement whereby they transfer their customer accounts receivables to third party financial institutions through wholly-owned and consolidated special purpose entities. The three agreements expire between May 2023 and October 2023 and may be further extended if mutually agreed to by the parties thereto.

All receivables transferred to third parties are valued at face value, which approximates fair value due to their short-term nature. The amount of the undivided percentage ownership interest in the accounts receivables transferred is determined in part by required loss reserves under the agreements.

Transfers of accounts receivable are accounted for as secured borrowings resulting in the recognition of short-term borrowings on the Consolidated Balance Sheets. As of December 31, 2022, the maximum amount of debt that could be recognized related to our accounts receivable programs is $500.0 million.

We had $347.2 million and no short-term borrowings related to the securitization transactions as of December 31, 2022 and 2021, respectively.

For the years ended December 31, 2022 and 2021, $347.2 million and zero, respectively, were recorded as cash flows from financing activities related to the change in short-term borrowings due to securitization transactions. For the accounts receivable transfer programs, we pay used facility fees for amounts borrowed, unused commitment fees for amounts not borrowed, and upfront renewal fees. Fees associated with the securitization transactions were $2.5 million, $1.4 million, and $2.6 million for the years ended December 31, 2022, 2021 and 2020, respectively. Columbia of Ohio, NIPSCO and Columbia of Pennsylvania remain responsible for collecting on the receivables securitized, and the receivables cannot be transferred to another party.

Term Credit Agreement. On December 20, 2022, we entered into a $1.0 billion term credit agreement with a syndicate of banks. The agreement matures on December 19, 2023 and interest charged on the borrowings depends on the variable rate structure elected at the time of each borrowing. The available variable rate structures from which we can choose are defined in the agreement. Under the agreement, we borrowed $1.0 billion on December 20, 2022 with an interest rate of SOFR plus 105 basis points. We had $1.0 billion outstanding with an interest rate of 5.37% as of December 31, 2022.

Items listed above, excluding the term credit agreement, are presented net in the Statements of Consolidated Cash Flows as their maturities are less than 90 days.

17. Leases

Lease Descriptions. We are the lessee for substantially all of our leasing activity, which includes operating and finance leases for corporate and field offices, railcars, fleet vehicles and certain IT assets. Our corporate and field office leases have remaining lease terms between 1 and 21 years with options to renew the leases for up to 25 years. We lease railcars to transport coal to and from our electric generation facilities in Indiana. Our railcars are specifically identified in the lease agreements which have remaining lease terms between 1 and 5 years with options to renew for 1 year. Our fleet vehicles include trucks, trailers and equipment that have been customized specifically for use in the utility industry. We lease fleet vehicles for 1 year terms, after which we have the option to extend on a month-to-month basis or terminate with written notice. We elected the short-term lease practical expedient, allowing us to not recognize ROU assets or lease liabilities for all leases with a term of 12 months or less. ROU assets and liabilities on our Consolidated Balance Sheets do not include obligations for possible fleet vehicle lease renewals beyond the initial lease term. While we have the ability to renew these leases beyond the initial term, we are not reasonably certain to do so. We lease the majority of our IT assets under 4 year lease terms. Ownership of leased IT assets is transferred to us at the end of the lease term.

We have not provided material residual value guarantees for our leases, nor do our leases contain material restrictions or covenants. Lease contracts containing renewal and termination options are mostly exercisable at our sole discretion. Certain of our real estate and railcar leases include renewal periods in the measurement of the lease obligation if we have deemed the renewals reasonably certain to be exercised.

With respect to service contracts involving the use of assets, if we have the right to direct the use of the asset and obtain substantially all economic benefits from the use of an asset, we account for the service contract as a lease. Unless specifically provided to us by the lessor, we utilize NiSource's collateralized incremental borrowing rate commensurate to the lease term as the discount rate for all of our leases. ASC 842 permits a lessee, by class of underlying asset, not to separate nonlease components from lease components. Our policy is to apply this expedient for our leases of fleet vehicles, IT assets and railcars when calculating their respective lease liabilities.

Lease costs for the years ended December 31, 2022 and December 31, 2021 are presented in the table below. These costs include both amounts recognized in expense and amounts capitalized as part of the cost of another asset. Income statement presentation for these costs (when ultimately recognized on the income statement) is also included:

Year Ended December 31, *(in millions)*	Income Statement Classification	**2022**	2021
Finance lease cost			
Amortization of right-of-use assets	Depreciation and amortization	**$ 31.9**	$ 28.8
Interest on lease liabilities	Interest expense, net	**8.5**	9.4
Total finance lease cost		**40.4**	38.2
Operating lease cost	Operation and maintenance	**10.4**	15.6
Total lease cost		**$ 50.8**	$ 53.8

Our right-of-use assets and liabilities are presented in the following lines on the Consolidated Balance Sheets:

At December 31, *(in millions)*	Balance Sheet Classification		**2022**		2021
Assets					
Finance leases	Net Property, Plant and Equipment	**$**	**153.4**	$	165.7
Operating leases	Deferred charges and other		**35.7**		33.8
Total leased assets		**$**	**189.1**		199.5
Liabilities					
Current					
Finance leases	Current portion of long-term debt	**$**	**30.0**		28.1
Operating leases	Other accruals		**4.8**		6.7
Noncurrent					
Finance leases	Long-term debt, excluding amounts due within one year		**144.7**		157.5
Operating leases	Other noncurrent liabilities		**31.9**		27.9
Total lease liabilities		**$**	**211.4**	$	220.2

Other pertinent information related to leases was as follows:

Year Ended December 31, *(in millions)*		**2022**		2021
Cash paid for amounts included in the measurement of lease liabilities				
Operating cash flows used for finance leases	**$**	**8.6**	$	9.4
Operating cash flows used for operating leases		**10.3**		15.4
Financing cash flows used for finance leases		**30.3**		25.7
Right-of-use assets obtained in exchange for lease obligations				
Finance leases		**19.3**		22.4
Operating leases	**$**	**8.8**	$	6.0

	December 31, 2022	December 31, 2021
Weighted-average remaining lease term (years)		
Finance leases	**9.9**	10.6
Operating leases	**7.7**	8.5
Weighted-average discount rate		
Finance leases	**5.1 %**	5.0 %
Operating leases	**4.0 %**	3.7 %

Maturities of our lease liabilities as of December 31, 2022 were as follows:

As of December 31, 2022, *(in millions)*	Total	Finance Leases	Operating Leases
2023	$ 46.8	$ 38.9	$ 7.9
2024	37.3	30.9	6.4
2025	30.3	24.5	5.8
2026	24.7	19.4	5.3
2027	19.9	15.4	4.5
Thereafter	110.8	97.4	13.4
Total lease payments	269.8	226.5	43.3
Less: Imputed interest	(58.4)	(51.8)	(6.6)
Total	$ 211.4	$ 174.7	$ 36.7
Reported as of December 31, 2022			
Short-term lease liabilities	34.8	30.0	4.8
Long-term lease liabilities	176.6	144.7	31.9
Total lease liabilities	$ 211.4	$ 174.7	$ 36.7

18. Fair Value

A. Fair Value Measurements

Recurring Fair Value Measurements

The following tables present financial assets and liabilities measured and recorded at fair value on our Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2022 and December 31, 2021:

Recurring Fair Value Measurements December 31, 2022 (*in millions*)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2022
Assets				
Risk management assets	$ —	$ 84.8	$ —	$ 84.8
Available-for-sale debt securities	—	151.6	—	151.6
Total	**$ —**	**$ 236.4**	**$ —**	**$ 236.4**
Liabilities				
Risk management liabilities	—	3.0	—	3.0
Total	**$ —**	**$ 3.0**	**$ —**	**$ 3.0**

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

Recurring Fair Value Measurements December 31, 2021 (*in millions*)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2021
Assets				
Risk management assets	$ —	$ 24.4	$ —	$ 24.4
Available-for-sale debt securities	—	171.8	—	171.8
Total	**$ —**	**$ 196.2**	**$ —**	**$ 196.2**
Liabilities				
Risk management liabilities	$ —	$ 144.2	$ —	$ 144.2
Total	**$ —**	**$ 144.2**	**$ —**	**$ 144.2**

Risk Management Assets and Liabilities. Risk management assets and liabilities include interest rate swaps, exchange-traded NYMEX futures and NYMEX options and non-exchange-based forward purchase contracts.

Level 1- When utilized, exchange-traded derivative contracts are based on unadjusted quoted prices in active markets and are classified within Level 1. These financial assets and liabilities are secured with cash on deposit with the exchange; therefore, nonperformance risk has not been incorporated into these valuations. These financial assets and liabilities are deemed to be cleared and settled daily by NYMEX as the related cash collateral is posted with the exchange. As a result of this exchange rule, NYMEX derivatives are considered to have no fair value at the balance sheet date for financial reporting purposes, and are presented in Level 1 net of posted cash; however, the derivatives remain outstanding and are subject to future commodity price fluctuations until they are settled in accordance with their contractual terms.

Level 2- Certain non-exchange-traded derivatives are valued using broker or over-the-counter, on-line exchanges. In such cases, these non-exchange-traded derivatives are classified within Level 2. Non-exchange-based derivative instruments include swaps, forwards, and options. In certain instances, these instruments may utilize models to measure fair value. We use a similar model to value similar instruments. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the asset or liability and market-corroborated inputs, (i.e., inputs derived principally from or corroborated by observable market data by correlation or other means). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized within Level 2.

Level 3- Certain derivatives trade in less active markets with a lower availability of pricing information and models may be utilized in the valuation. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized within Level 3.

Credit risk is considered in the fair value calculation of derivative instruments that are not exchange-traded. Credit exposures are adjusted to reflect collateral agreements that reduce exposures. As of December 31, 2022 and 2021, there were no material transfers between fair value hierarchies. Additionally, there were no changes in the method or significant assumptions used to estimate the fair value of our financial instruments.

NIPSCO has entered into long-term forward natural gas purchase instruments to lock in a fixed price for its natural gas customers. We value these contracts using a pricing model that incorporates market-based information when available, as these instruments trade less frequently and are classified within Level 2 of the fair value hierarchy. For additional information, see Note 10, "Risk Management Activities."

Available-for-Sale Debt Securities. Available-for-sale debt securities are investments pledged as collateral for trust accounts related to our wholly-owned insurance company. We value U.S. Treasury, corporate debt and mortgage-backed securities using a matrix pricing model that incorporates market-based information. These securities trade less frequently and are classified within Level 2.

Our available-for-sale debt securities impairments are recognized periodically using an allowance approach. At each reporting date, we utilize a quantitative and qualitative review process to assess the impairment of available-for-sale debt securities at the individual security level. For securities in a loss position, we evaluate our intent to sell or whether it is more-likely-than-not that we will be required to sell the security prior to the recovery of its amortized cost. If either criteria is met, the loss is recognized in earnings immediately, with the offsetting entry to the carrying value of the security. If both criteria are not met, we perform an analysis to determine whether the unrealized loss is related to credit factors. The analysis focuses on a variety of factors that include, but are not limited to, downgrade on ratings of the security, defaults in the current reporting period or projected defaults in the future, the security's yield spread over treasuries, and other relevant market data. If the unrealized loss is not related to credit factors, it is included in other comprehensive income. If the unrealized loss is related to credit factors, the loss is recognized as credit loss expense in earnings during the period, with an offsetting entry to the allowance for credit losses. The amount of the credit loss recorded to the allowance account is limited by the amount at which the security's fair value is less than its amortized cost basis. If certain amounts recorded in the allowance for credit losses are deemed uncollectible, the allowance on the uncollectible portion will be charged off, with an offsetting entry to the carrying value of the security. Subsequent improvements to the estimated credit losses of available-for-sale debt securities will be recognized immediately in earnings. As of December 31, 2022 and December 31, 2021, we recorded $0.9 million and $0.2 million, respectively, as an allowance for credit losses on available-for-sale debt securities as a result of the analysis described above. Continuous credit monitoring and portfolio credit balancing mitigates our risk of credit losses on our available-for-sale debt securities.

The amortized cost, gross unrealized gains and losses, allowance for credit losses, and fair value of available-for-sale securities at December 31, 2022 and 2021 were:

December 31, 2022 *(in millions)*	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses[1]	Allowance for Credit Losses	Fair Value
Available-for-sale debt securities					
U.S. Treasury debt securities	$ 67.7	$ —	$ (4.5)	$ —	$ 63.2
Corporate/Other debt securities	99.0	—	(9.7)	(0.9)	88.4
Total	**$ 166.7**	**$ —**	**$ (14.2)**	**$ (0.9)**	**$ 151.6**

December 31, 2021 *(in millions)*	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses[2]	Allowance for Credit Losses	Fair Value
Available-for-sale debt securities					
U.S. Treasury debt securities	$ 52.8	$ 0.1	$ (0.4)	$ —	$ 52.5
Corporate/Other debt securities	116.5	3.7	(0.7)	(0.2)	119.3
Total	**$ 169.3**	**$ 3.8**	**$ (1.1)**	**$ (0.2)**	**$ 171.8**

[1] Fair value of U.S. Treasury debt securities and Corporate/Other debt securities in an unrealized loss position without an allowance for credit losses is $61.0 and $85.5 million, respectively, at December 31, 2022.
[2] Fair value of U.S. Treasury debt securities and Corporate/Other debt securities in an unrealized loss position without an allowance for credit losses is $36.2 million and $35.4 million, respectively, at December 31, 2021.

Realized gains and losses on available-for-sale securities were immaterial for the year-ended December 31, 2022 and 2021.

The cost of maturities sold is based upon specific identification. At December 31, 2022, approximately $5.2 million of U.S. Treasury debt securities and approximately $5.8 million of Corporate/Other debt securities have maturities of less than a year.

There are no material items in the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis for the years ended December 31, 2022 and 2021.

Non-recurring Fair Value Measurements

We measure the fair value of certain assets, including goodwill, on a non-recurring basis, typically when events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable.

Purchase Contract Liability. On April 19, 2021, we recorded the purchase contract liability at fair value using a discounted cash flow method and observable, market-corroborated inputs. This estimate was made at April 19, 2021, and will not be remeasured at each subsequent balance sheet date. It has been categorized within Level 2 of the fair value hierarchy. Refer to Note 13, "Equity," for additional information.

B. Other Fair Value Disclosures for Financial Instruments. The carrying amount of cash and cash equivalents, restricted cash, notes receivable, customer deposits and short-term borrowings is a reasonable estimate of fair value due to their liquid or short-term nature. Our long-term borrowings are recorded at historical amounts.

The following method and assumptions were used to estimate the fair value of each class of financial instruments.

Long-term debt. The fair value of outstanding long-term debt is estimated based on the quoted market prices for the same or similar securities. Certain premium costs associated with the early settlement of long-term debt are not taken into consideration in determining fair value. These fair value measurements are classified within Level 2 of the fair value hierarchy. For the years ended December 31, 2022 and 2021, there was no change in the method or significant assumptions used to estimate the fair value of long-term debt.

The carrying amount and estimated fair values of these financial instruments were as follows:

At December 31, *(in millions)*	**Carrying Amount 2022**	**Estimated Fair Value 2022**	Carrying Amount 2021	Estimated Fair Value 2021
Long-term debt (including current portion)	**$ 9,553.6**	**$ 8,479.4**	$ 9,241.5	$ 10,415.7

19. Other Commitments and Contingencies

A. Contractual Obligations. We have certain contractual obligations requiring payments at specified periods. The obligations include long-term debt, lease obligations, energy commodity contracts and obligations for various services including pipeline capacity and outsourcing of IT services. The total contractual obligations in existence at December 31, 2022 and their maturities were:

(in millions)	Total	2023	2024	2025	2026	2027	After
Long-term debt [1]	$ 9,455.0	$ —	$ —	$ 1,260.0	$ —	$ 1,090.0	$ 7,105.0
Interest payments on long-term debt	5,890.4	351.6	351.6	351.6	339.1	319.7	4,176.8
Finance leases[2]	226.5	38.9	30.9	24.5	19.4	15.4	97.4
Operating leases[3]	43.3	7.9	6.4	5.8	5.3	4.5	13.4
Energy commodity contracts	231.7	119.7	76.0	36.0	—	—	—
Service obligations:							
Pipeline service obligations	2,484.9	642.2	556.9	410.5	337.2	328.8	209.3
IT service obligations	177.4	71.9	50.0	41.3	11.4	2.8	—
Other liabilities[4]	654.2	612.5	6.2	5.9	5.2	5.2	19.2
Total contractual obligations	$ 19,163.4	$ 1,844.7	$ 1,078.0	$ 2,135.6	$ 717.6	$ 1,766.4	$ 11,621.1

[1] Long-term debt balance excludes unamortized issuance costs and discounts of $76.1 million.
[2] Finance lease payments shown above are inclusive of interest totaling $51.8 million.
[3] Operating lease payments shown above are inclusive of interest totaling $6.6 million. Operating lease balances do not include obligations for possible fleet vehicle lease renewals beyond the initial lease term. While we have the ability to renew these leases beyond the initial term, we are not reasonably certain to do so as they are renewed month-to-month after the first year.
[4] Other liabilities shown above are inclusive of the Rosewater, Indiana Crossroads Wind, and Indiana Crossroads Solar Developer payments due in 2023 and Equity Unit purchase contract liability payments to be made in 2023.

Purchase and Service Obligations. We have entered into various purchase and service agreements whereby we are contractually obligated to make certain minimum payments in future periods. Our purchase obligations are for the purchase of physical quantities of natural gas, electricity and coal. Our service agreements encompass a broad range of business support and maintenance functions which are generally described below.

Our subsidiaries have entered into various energy commodity contracts to purchase physical quantities of natural gas, electricity and coal. These amounts represent the minimum quantity of these commodities we are obligated to purchase at both fixed and variable prices. To the extent contractual purchase prices are variable, obligations disclosed in the table above are valued at market prices as of December 31, 2022.

NIPSCO has power purchase arrangements representing a total of 500 MW of wind power, with contracts expiring between 2024 and 2040. No minimum quantities are specified within these agreements due to the variability of electricity generation from wind, so no amounts related to these contracts are included in the table above. Upon early termination of one of these agreements by NIPSCO for any reason (other than material breach by the counterparties), NIPSCO may be required to pay a termination charge that could be material depending on the events giving rise to termination and the timing of the termination.

We have pipeline service agreements that provide for pipeline capacity, transportation and storage services. These agreements, which have expiration dates ranging from 2023 to 2038, require us to pay fixed monthly charges.

NIPSCO has contracts with three major rail operators providing coal transportation services for which there are certain minimum payments. These service contracts extend for various periods through 2028.

We have executed agreements with multiple IT service providers. The agreements extend for various periods through 2028.

B. Guarantees and Indemnities. We and certain of our subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries as part of normal business. Such agreements include guarantees and stand-by letters of credit. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. At December 31, 2022 and 2021, we issued stand-by letters of credit of $10.2 million and $18.9 million, respectively, for the benefit of third parties.

We provide guarantees related to our future performance under BTAs for our renewable generation projects. At December 31, 2022 and 2021, our guarantees for multiple BTAs totaled $841.6 million and $288.9 million, respectively. The amount of each guaranty will decrease upon the substantial completion of the construction of the facilities. See "- F. Other Matters - Generation Transition," below for more information.

C. Legal Proceedings. On September 13, 2018, a series of fires and explosions occurred in Lawrence, Andover, and North Andover, Massachusetts related to the delivery of natural gas by Columbia of Massachusetts (the "Greater Lawrence Incident").

We have been subject to inquiries and investigations by government authorities and regulatory agencies regarding the Greater Lawrence Incident. On February 26, 2020, the Company and Columbia of Massachusetts entered into agreements with the U.S. Attorney's Office for the District of Massachusetts to resolve the U.S. Attorney's Office's investigation relating to the Greater Lawrence Incident, as described below. The Company and Columbia of Massachusetts entered into an agreement with the Massachusetts Attorney General's Office (among other parties) to resolve the Massachusetts DPU and the Massachusetts Attorney General's Office investigations, that was approved by the Massachusetts DPU on October 7, 2020 as part of the sale of the Massachusetts Business to Eversource.

U.S. Department of Justice Investigation. On February 26, 2020, the Company and Columbia of Massachusetts entered into agreements with the U.S. Attorney's Office to resolve the U.S. Attorney's Office's investigation relating to the Greater Lawrence Incident. Columbia of Massachusetts agreed to plead guilty in the United States District Court for the District of Massachusetts (the "Court") to violating the Natural Gas Pipeline Safety Act (the "Plea Agreement"), and the Company entered into a Deferred Prosecution Agreement (the "DPA").

On March 9, 2020, Columbia of Massachusetts entered its guilty plea pursuant to the Plea Agreement. The Court sentenced Columbia of Massachusetts on June 23, 2020, in accordance with the terms of the Plea Agreement (as modified). On June 23, 2021, the Court terminated Columbia of Massachusetts' period of probation under the Plea Agreement, which marked the completion of all terms of the Plea Agreement.

Under the DPA, the U.S. Attorney's Office agreed to defer prosecution of the Company in connection with the Greater Lawrence Incident for a three-year period ending on February 26, 2023 (which three-year period may be extended for twelve (12) months upon the U.S. Attorney's Office's determination of a breach of the DPA) subject to certain obligations of the Company, including, but not limited to, the Company's agreement, as to each of the Company's subsidiaries involved in the distribution of gas through pipeline facilities in Massachusetts, Indiana, Ohio, Pennsylvania, Maryland, Kentucky and Virginia to implement and adhere to each of the recommendations from the NTSB stemming from the Greater Lawrence Incident. Pursuant to the DPA, if the Company complies with all of its obligations under the DPA, the U.S. Attorney's Office will not file any criminal charges against the Company related to the Greater Lawrence Incident.

Private Actions. Various lawsuits, including several purported class action lawsuits, were filed by various affected residents or businesses in Massachusetts state courts against the Company and/or Columbia of Massachusetts in connection with the Greater Lawrence Incident.

On March 12, 2020, the Court granted final approval of the settlement of the consolidated class action. With respect to claims not included in the consolidated class action, many of the asserted wrongful death and bodily injury claims have been settled, and we continue to discuss potential settlements with remaining claimants. The outcomes and impacts of such private actions are uncertain at this time.

FERC Investigation. In April 2022, NIPSCO was notified that the FERC Office of Enforcement ("OE") is conducting an investigation of an industrial customer for allegedly manipulating the MISO Demand Response ("DR") market. The customer and NIPSCO are cooperating with the investigation. If the OE ultimately were to seek to require the customer to repay any portion of the DR revenue received from MISO, it is reasonably possible that the OE would also seek to require NIPSCO to disgorge administrative fees and foregone margin charges that NIPSCO collected pursuant to its own IURC-approved tariff. NIPSCO currently estimates the maximum amount of its disgorgement exposure to be $9.7 million, and the investigation is still ongoing. NIPSCO intends to seek indemnification under its agreements with the customer for any liability NIPSCO incurs related to this matter.

Other Claims and Proceedings. We are also party to certain other claims, regulatory and legal proceedings arising in the ordinary course of business in each state in which we have operations, none of which we believe to be individually material at this time.

Due to the inherent uncertainty of litigation, there can be no assurance that the resolution of any particular claim, proceeding or investigation would not have a material adverse effect on our results of operations, financial position or liquidity. If one or more other matters were decided against us, the effects could be material to our results of operations in the period in which we would be required to record or adjust the related liability and could also be material to our cash flows in the periods that we would be required to pay such liability.

D. Other Greater Lawrence Incident Matters. In connection with the Greater Lawrence Incident, Columbia of Massachusetts, in cooperation with the Massachusetts Governor's office, replaced the entire affected pipeline system. We invested approximately $258 million of capital spend for the pipeline replacement; this work was completed in 2019. We maintain property insurance for gas pipelines and other applicable property. Columbia of Massachusetts filed a proof of loss with its property insurer for the pipeline replacement. In January 2020, we filed a lawsuit against the property insurer, seeking payment of our property claim. On October 27, 2021, NiSource and the property insurer filed cross motions for summary judgment, each asking the court to determine whether there was coverage under the policy. After the cross motions for summary judgment were fully briefed, we reached an agreement to settle the coverage dispute for $105.0 million. After settlement payment was made, NiSource and its property insurer stipulated to the dismissal of the lawsuit on March 16, 2022.

E. Environmental Matters. Our operations are subject to environmental statutes and regulations related to air quality, water quality, hazardous waste and solid waste. We believe that we are in substantial compliance with the environmental regulations currently applicable to our operations.

It is management's continued intent to address environmental issues in cooperation with regulatory authorities in such a manner as to achieve mutually acceptable compliance plans. However, there can be no assurance that fines and penalties will not be incurred. Management expects the majority of environmental assessment and remediation costs and asset retirement costs, further described below, to be recoverable through rates. See Note 9, "Regulatory Matters," for additional detail.

As of December 31, 2022 and 2021, we had recorded a liability of $86.5 million and $91.1 million, respectively, to cover environmental remediation at various sites. This liability is included in "Other accruals" and "Other noncurrent liabilities" in the Consolidated Balance Sheets. We recognize costs associated with environmental remediation obligations when the incurrence of such costs is probable and the amounts can be reasonably estimated. The original estimates for remediation activities may differ materially from the amount ultimately expended. The actual future expenditures depend on many factors, including laws and regulations, the nature and extent of impact and the method of remediation. These expenditures are not currently estimable at some sites. We periodically adjust our liability as information is collected and estimates become more refined. See Note 8, "Asset Retirement Obligations," for a discussion of all obligations, including those discussed below.

CERCLA. Our subsidiaries are potentially responsible parties at waste disposal sites under the CERCLA and similar state laws. Under CERCLA, each potentially responsible party can be held jointly, severally and strictly liable for the remediation costs as the EPA, or state, can allow the parties to pay for remedial action or perform remedial action themselves and request reimbursement from the potentially responsible parties. Our affiliates have retained CERCLA environmental liabilities, including remediation liabilities, associated with certain current and former operations. At this time, NIPSCO cannot estimate the full cost of remediating properties that have not yet been investigated, but it is possible that the future costs could be material to the Consolidated Financial Statements.

MGP. We maintain a program to identify and investigate former MGP sites where Gas Distribution Operations subsidiaries or predecessors may have liability. The program has identified 53 such sites where liability is probable. Remedial actions at many of these sites are being overseen by state or federal environmental agencies through consent agreements or voluntary remediation agreements.

We utilize a probabilistic model to estimate our future remediation costs related to MGP sites. The model was prepared with the assistance of a third party and incorporates our experience and general industry experience with remediating MGP sites. We complete an annual refresh of the model in the second quarter of each fiscal year. No material changes to the estimated future remediation costs were noted as a result of the refresh completed as of June 30, 2022. Our total estimated liability related to the facilities subject to remediation was $81.0 million and $85.1 million at December 31, 2022 and 2021, respectively. The liability represents our best estimate of the probable cost to remediate the MGP sites. We believe that it is reasonably possible that remediation costs could vary by as much as $17 million in addition to the costs noted above. Remediation costs are estimated based on the best available information, applicable remediation standards at the balance sheet date, and experience with similar facilities.

CCRs. We continue to meet the compliance requirements established in the EPA's final rule for the regulation of CCRs. The CCR rule also resulted in revisions to previously recorded legal obligations associated with the retirement of certain NIPSCO facilities. The actual asset retirement costs related to the CCR rule may vary substantially from the estimates used to record the increased asset retirement obligation due to the uncertainty about the requirements that will be established by environmental authorities, compliance strategies that will be used and the preliminary nature of available data used to estimate costs. As allowed by the rule, NIPSCO will continue to collect data over time to determine the specific compliance solutions and associated costs and, as a result, the actual costs may vary.

F. Other Matters

Generation Transition. NIPSCO has executed several PPAs to purchase 100% of the output from renewable generation facilities at a fixed price per MWh. Each facility supplying the energy will have an associated nameplate capacity, and payments under the PPAs will not begin until the associated generation facility is constructed by the owner/seller. NIPSCO has also executed several BTAs with developers to construct renewable generation facilities. NIPSCO's purchase obligation under each respective BTA is dependent on satisfactory approval of the BTA by the IURC, successful execution by NIPSCO of an agreement with a tax equity partner and timely completion of construction. NIPSCO has received IURC approval for all of its BTAs and PPAs. NIPSCO and the tax equity partner, for each respective BTA, are obligated to make cash contributions to the JV that acquires the project at the date construction is substantially complete. Certain agreements require NIPSCO to make partial payments upon the developer's completion of significant construction milestones. Once the tax equity partner has earned its negotiated rate of return and we have reached the agreed upon contractual date, NIPSCO has the option to purchase at fair market value the remaining interest in the JV from the tax equity partner.

Employee Separation Benefits. In the third quarter of 2020, we launched a program to evaluate our organizational structure under the auspices of NiSource Next, which continued into 2021. We recognized the majority of the related severance expense in 2020 when the employees accepted severance offers, absent a retention period. For employees that have a retention period, expense will be recognized over the remaining service period. The total severance expense for employees was approximately $38 million, with substantially all of it incurred and paid to date.

20. Accumulated Other Comprehensive Loss

The following table displays the activity of Accumulated Other Comprehensive Loss, net of tax:

(in millions)	Gains and Losses on Securities[1]	Gains and Losses on Cash Flow Hedges[1]	Pension and OPEB Items[1]	Accumulated Other Comprehensive Loss[1]
Balance as of January 1, 2020	**$ 3.3**	**$ (77.2)**	**$ (18.7)**	**$ (92.6)**
Other comprehensive income (loss) before reclassifications	3.3	(70.8)	2.9	(64.6)
Amounts reclassified from accumulated other comprehensive loss	(0.6)	0.1	1.0	0.5
Net current-period other comprehensive income (loss)	2.7	(70.7)	3.9	(64.1)
Balance as of December 31, 2020	**$ 6.0**	**$ (147.9)**	**$ (14.8)**	**$ (156.7)**
Other comprehensive income (loss) before reclassifications	(3.5)	25.3	6.6	28.4
Amounts reclassified from accumulated other comprehensive loss	(0.4)	0.1	1.8	1.5
Net current-period other comprehensive income (loss)	(3.9)	25.4	8.4	29.9
Balance as of December 31, 2021	**$ 2.1**	**$ (122.5)**	**$ (6.4)**	**$ (126.8)**
Other comprehensive income (loss) before reclassifications	(13.7)	109.7	(8.9)	87.1
Amounts reclassified from accumulated other comprehensive loss	0.4	0.2	2.0	2.6
Net current-period other comprehensive income (loss)	(13.3)	109.9	(6.9)	89.7
Balance as of December 31, 2022	**$ (11.2)**	**$ (12.6)**	**$ (13.3)**	**$ (37.1)**

[1]All amounts are net of tax. Amounts in parentheses indicate debits.

21. Business Segment Information

At December 31, 2022, our operations are divided into two primary reportable segments, the Gas Distribution Operations and the Electric Operations segments. The remainder of our operations, which are not significant enough on a stand-alone basis to warrant treatment as an operating segment, are presented as "Corporate and Other" and primarily are comprised of interest expense on holding company debt and unallocated corporate costs and activities. Refer to Note 3, "Revenue Recognition," for additional information on our segments and their sources of revenues. The following table provides information about our reportable segments. We use operating income as our primary measurement for each of the reported segments and make decisions on finance, dividends and taxes at the corporate level on a consolidated basis. Segment revenues include intersegment sales to affiliated subsidiaries, which are eliminated in consolidation. Affiliated sales are recognized on the basis of prevailing market, regulated prices or at levels provided for under contractual agreements. Operating income is derived from revenues and expenses directly associated with each segment.

Year Ended December 31, *(in millions)*		2022		2021		2020
Operating Revenues						
Gas Distribution Operations						
Unaffiliated	$	**4,007.2**	$	3,171.2	$	3,128.1
Intersegment		**12.6**		12.3		12.1
Total		**4,019.8**		3,183.5		3,140.2
Electric Operations						
Unaffiliated		**1,830.9**		1,696.3		1,535.9
Intersegment		**0.8**		0.8		0.7
Total		**1,831.7**		1,697.1		1,536.6
Corporate and Other						
Unaffiliated		**12.5**		32.1		17.7
Intersegment		**465.0**		460.3		449.8
Total		**477.5**		492.4		467.5
Eliminations		**(478.4)**		(473.4)		(462.6)
Consolidated Operating Revenues	$	**5,850.6**	$	4,899.6	$	4,681.7

Year Ended December 31, *(in millions)*		2022		2021		2020
Operating Income (Loss)						
Gas Distribution Operations[(1)]	$	**915.8**	$	617.5	$	199.1
Electric Operations		**362.4**		387.8		348.8
Corporate and Other		**(12.4)**		1.6		2.9
Consolidated Operating Income	$	**1,265.8**	$	1,006.9	$	550.8
Depreciation and Amortization						
Gas Distribution Operations	$	**415.9**	$	383.0	$	363.1
Electric Operations		**362.9**		329.4		321.3
Corporate and Other		**42.0**		36.0		41.5
Consolidated Depreciation and Amortization	$	**820.8**	$	748.4	$	725.9
Assets						
Gas Distribution Operations	$	**16,986.5**	$	15,153.7	$	13,433.0
Electric Operations		**7,992.6**		7,178.9		6,443.1
Corporate and Other		**1,757.5**		1,824.3		2,164.4
Consolidated Assets	$	**26,736.6**	$	24,156.9	$	22,040.5
Capital Expenditures[(2)]						
Gas Distribution Operations	$	**1,682.3**	$	1,406.4	$	1,266.9
Electric Operations		**574.5**		517.4		422.8
Corporate and Other		**41.2**		16.6		31.1
Consolidated Capital Expenditures	$	**2,298.0**	$	1,940.4	$	1,720.8

[(1)]In 2020, Gas Distribution Operations reflects the loss of $412.4 million on the sale of the Massachusetts Business.

[(2)]Amounts differ from those presented on the Statements of Consolidated Cash Flows primarily due to the inclusion of capital expenditures in current liabilities, the capitalized portion of the Corporate Incentive Plan payout, and AFUDC Equity.

22. Other, Net

The following table displays the components of Other, Net included on the Statements of Consolidated Income (Loss):

Year Ended December 31, *(in millions)*	**2022**	2021	2020
Interest income	**$ 4.3**	$ 4.0	$ 5.5
AFUDC equity	**15.1**	13.1	9.9
Charitable contributions	**(4.4)**	(11.5)	(1.5)
Pension and other postretirement non-service cost[(1)]	**27.6**	35.5	9.3
Sale of emission reduction credits	**—**	—	4.6
Interest rate swap settlement gain[(2)]	**10.0**	—	—
Miscellaneous	**(0.4)**	(0.3)	4.3
Total Other, net	**$ 52.2**	$ 40.8	$ 32.1

(1) See Note 12, "Pension and Other Postemployment Benefits," for additional information.
(2) See Note 10, "Risk Management Activities," for additional information.

23. Interest Expense, Net

The following table displays the components of Interest Expense, Net included on the Statements of Consolidated Income (Loss):

Year Ended December 31, *(in millions)*	**2022**	2021	2020
Interest on long-term debt	**$ 344.5**	$ 336.4	$ 354.2
Interest on short-term borrowings	**22.7**	0.6	14.7
Debt discount/cost amortization	**11.7**	11.0	9.1
Accounts receivable securitization fees	**2.5**	1.4	2.6
Allowance for borrowed funds used and interest capitalized during construction	**(6.7)**	(4.6)	(7.0)
Debt-based post-in-service carrying charges	**(21.1)**	(14.7)	(14.6)
Other	**8.0**	11.0	11.7
Total Interest Expense, net	**$ 361.6**	$ 341.1	$ 370.7

24. Supplemental Cash Flow Information

The following table provides additional information regarding our Consolidated Statements of Cash Flows for the years ended December 31, 2022, 2021 and 2020:

Year Ended December 31, *(in millions)*	**2022**	2021	2020
Supplemental Disclosures of Cash Flow Information			
Non-cash transactions:			
Capital expenditures included in current liabilities	**$ 275.1**	$ 245.7	$ 170.4
Assets acquired under a finance lease	**19.3**	22.4	59.3
Assets acquired under an operating lease	**8.8**	6.0	10.9
Reclassification of other property to regulatory assets(1)	**—**	607.6	—
Assets recorded for asset retirement obligations(2)	**6.3**	12.0	91.5
Obligation to developer at formation of JV(3)	**—**	277.5	69.7
Purchase contract liability, net of fees and payments(4)	**65.0**	129.4	—
Schedule of interest and income taxes paid:			
Cash paid for interest on long-term debt, net of interest capitalized amounts	**$ 343.8**	$ 322.4	$ 349.0
Cash paid for interest on finance leases	**8.5**	9.4	11.1
Cash paid for income taxes, net of refunds(5)	**7.2**	5.4	(1.0)

(1)See Note 9, "Regulatory Matters," for additional information.
(2)See Note 8, "Asset Retirement Obligations," for additional information.
(3)Represents investing non-cash activity. See Note 4, "Variable Interest Entities," for additional information.
(4)Refer to Note 13, "Equity," for additional information.
(5)Amount of refunds in 2020 was greater than the amount of tax payments due to overpayments in 2019.

NISOURCE INC.

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS

Twelve months ended December 31, 2022

($ in millions)	Balance Jan. 1, 2022	Additions: Charged to Costs and Expenses	Additions: Charged to Other Account [1]	Deductions for Purposes for which Reserves were Created	Balance Dec. 31, 2022
Reserves Deducted in Consolidated Balance Sheet from Assets to Which They Apply:					
Reserve for accounts receivable	$ 23.5	$ 20.6	$ 36.4	$ 56.6	$ 23.9
Reserve for deferred charges and other	2.3	—	(1.3)	—	1.0

Twelve months ended December 31, 2021

($ in millions)	Balance Jan. 1, 2021	Additions: Charged to Costs and Expenses	Additions: Charged to Other Account [1]	Deductions for Purposes for which Reserves were Created	Balance Dec. 31, 2021
Reserves Deducted in Consolidated Balance Sheet from Assets to Which They Apply:					
Reserve for accounts receivable	$ 52.3	$ 18.3	$ 6.4	$ 53.5	$ 23.5
Reserve for deferred charges and other	—	—	2.3	—	2.3

Twelve months ended December 31, 2020

($ in millions)	Balance Jan. 1, 2020	Additions: Charged to Costs and Expenses	Additions: Charged to Other Account [1]	Deductions for Purposes for which Reserves were Created	Balance Dec. 31, 2020
Reserves Deducted in Consolidated Balance Sheet from Assets to Which They Apply:					
Reserve for accounts receivable	$ 19.2	$ 31.6	$ 33.0	$ 31.5	$ 52.3
Reserve for other investments	3.0	—	—	3.0	—

[1] Charged to Other Accounts reflects the deferral of bad debt expense to a regulatory asset or the movement of the reserve between short term and long term.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our chief executive officer and chief financial officer are responsible for evaluating the effectiveness of disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)). Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by the Company in reports that are filed or submitted under the Exchange Act are accumulated and communicated to management, including our chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our chief executive officer and chief financial officer concluded that, as of the end of the period covered by this report, disclosure controls and procedures were effective to provide reasonable assurance that financial information was processed, recorded and reported accurately.

Management's Annual Report on Internal Control over Financial Reporting

Our management, including our chief executive officer and chief financial officer, are responsible for establishing and maintaining internal control over financial reporting, as such term is defined under Rule 13a-15(f) or Rule 15d-15(f) promulgated under the Exchange Act. However, management would note that a control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our management has adopted the 2013 framework set forth in the Committee of Sponsoring Organizations of the Treadway Commission report, Internal Control - Integrated Framework, the most commonly used and understood framework for evaluating internal control over financial reporting, as its framework for evaluating the reliability and effectiveness of internal control over financial reporting. During 2022, we conducted an evaluation of our internal control over financial reporting. Based on this evaluation, management concluded that our internal control over financial reporting was effective as of the end of the period covered by this annual report.

Deloitte & Touche LLP, our independent registered public accounting firm, issued an attestation report on our internal controls over financial reporting which is included herein.

Changes in Internal Controls

There have been no changes in our internal control over financial reporting during the most recently completed quarter covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

NiSource Inc.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of NiSource Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of NiSource Inc. and subsidiaries (the "Company") as of December 31, 2022, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2022, of the Company and our report dated February 22, 2023, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP
Columbus, Ohio
February 22, 2023

ITEM 9B. OTHER INFORMATION

NISOURCE INC.

Not applicable.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

NISOURCE INC.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Except for the information required by this item with respect to our executive officers included at the end of Part I of this report on Form 10-K, the information required by this Item 10 is incorporated herein by reference to the discussion in "Proposal 1 Election of Directors," "Corporate Governance - Board Committee Composition," "Corporate Governance - Code of Business Conduct," and "Delinquent Section 16(a) Reports" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 23, 2023.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item 11 is incorporated herein by reference to the discussion in "Corporate Governance - Compensation Committee Interlocks and Insider Participation," "2022 Director Compensation," "2022 Executive Compensation," "Compensation Discussion and Analysis (CD&A)," and "Compensation and Human Capital Committee Report" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 23, 2023.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item 12 is incorporated herein by reference to the discussion in "Security Ownership of Certain Beneficial Owners and Management," and "Equity Compensation Plan Information" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 23, 2023.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item 13 is incorporated herein by reference to the discussion in "Corporate Governance - Policies and Procedures with Respect to Transactions with Related Persons" and "Corporate Governance - Director Independence" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 23, 2023.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item 14 is incorporated herein by reference to the discussion in "Independent Registered Public Accounting Firm Fees" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 23, 2023.

PART IV

NiSource Inc.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

Financial Statements and Financial Statement Schedules

The following financial statements and financial statement schedules filed as a part of the Annual Report on Form 10-K are included in Item 8, "Financial Statements and Supplementary Data."

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Exhibits

The exhibits filed herewith as a part of this report on Form 10-K are listed on the Exhibit Index below. Each management contract or compensatory plan or arrangement of ours, listed on the Exhibit Index, is separately identified by an asterisk.

Pursuant to Item 601(b), paragraph (4)(iii)(A) of Regulation S-K, certain instruments representing long-term debt of our subsidiaries have not been included as Exhibits because such debt does not exceed 10% of the total assets of ours and our subsidiaries on a consolidated basis. We agree to furnish a copy of any such instrument to the SEC upon request.

EXHIBIT NUMBER	DESCRIPTION OF ITEM
(1.1)	Form of Equity Distribution Agreement (incorporated by reference to Exhibit 1.1 of the NiSource Inc. Form 8-K filed on February 22, 2021).
(1.2)	Form of Master Forward Sale Confirmation (incorporated by reference to Exhibit 1.2 of the NiSource Inc. Form 8-K filed on February 22, 2021).
(2.1)	Separation and Distribution Agreement, dated as of June 30, 2015, by and between NiSource Inc. and Columbia Pipeline Group, Inc. (incorporated by reference to Exhibit 2.1 to the NiSource Inc. Form 8-K filed on July 2, 2015).
(2.2)	Asset Purchase Agreement, dated as of February 26, 2020, by and among NiSource Inc., Bay State Gas Company d/b/a Columbia Gas of Massachusetts and Eversource Energy (incorporated by reference to Exhibit 2.1 of the NiSource Inc. Form 8-K filed on February 27, 2020). (incorporated by reference to Exhibit 2.2 to the NiSource Inc. Form 10-K filed on February 17, 2021).
(3.1)	Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Registrant’s Form 10-Q, filed with the Commission on August 3, 2015).
(3.2)	Certificate of Amendment of Amended and Restated Certificate of Incorporation of NiSource dated May 7, 2019 (incorporated by reference to Exhibit 3.1 of the NiSource Inc. Form 8-K filed on May 8, 2019).
(3.3)	Bylaws of NiSource Inc., as amended and restated through August 9, 2022 (incorporated by reference to Exhibit 3.1 to the NiSource Inc. Form 8-K filed on August 10, 2022).
(3.4)	Certificate of Designations of 5.65% Series A Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock (incorporated by reference to Exhibit 3.1 of the NiSource Inc. Form 8-K filed on June 12, 2018).
(3.5)	Certificate of Designations of 6.50% Series B Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock (incorporated by reference to Exhibit 3.1 of the NiSource Inc. Form 8-K filed on December 6, 2018).
(3.6)	Certificate of Designations of Series B-1 Preferred Stock (incorporated by reference to Exhibit 3.1 to the NiSource Inc. Form 8-K filed on December 27, 2018).
(3.7)	Certificate of Designations with respect to the Series C Mandatory Convertible Preferred Stock, dated April 19, 2021 (incorporated by reference to Exhibit 3.1 of the NiSource Inc. Form 8-K filed on April 19, 2021).

(4.1)	Indenture, dated as of March 1, 1988, by and between Northern Indiana Public Service Company ("NIPSCO") and Manufacturers Hanover Trust Company, as Trustee (incorporated by reference to Exhibit 4 to the NIPSCO Registration Statement (Registration No. 33-44193)).
(4.2)	First Supplemental Indenture, dated as of December 1, 1991, by and between Northern Indiana Public Service Company and Manufacturers Hanover Trust Company, as Trustee (incorporated by reference to Exhibit 4.1 to the NIPSCO Registration Statement (Registration No. 33-63870)).
(4.3)	Indenture Agreement, dated as of February 14, 1997, by and between NIPSCO Industries, Inc., NIPSCO Capital Markets, Inc. and Chase Manhattan Bank as trustee (incorporated by reference to Exhibit 4.1 to the NIPSCO Industries, Inc. Registration Statement (Registration No. 333-22347)).
(4.4)	Second Supplemental Indenture, dated as of November 1, 2000, by and among NiSource Capital Markets, Inc., NiSource Inc., New NiSource Inc., and The Chase Manhattan Bank, as trustee (incorporated by reference to Exhibit 4.45 to the NiSource Inc. Form 10-K for the period ended December 31, 2000).
(4.5)	Indenture, dated November 14, 2000, among NiSource Finance Corp., NiSource Inc., as guarantor, and The Chase Manhattan Bank, as Trustee (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form S-3, dated November 17, 2000 (Registration No. 333-49330)).
(4.6)	Form of 3.490% Notes due 2027 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on May 17, 2017).
(4.7)	Form of 4.375% Notes due 2047 (incorporated by reference to Exhibit 4.2 to the NiSource Inc. Form 8-K filed on May 17, 2017).
(4.8)	Form of 3.950% Notes due 2048 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on September 8, 2017).
(4.9)	Form of 2.650% Notes due 2022 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on November 14, 2017).
(4.10)	Second Supplemental Indenture, dated as of November 30, 2017, between NiSource Inc. and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.4 to Post-Effective Amendment No. 1 to Form S-3 filed November 30, 2017 (Registration No. 333-214360)).
(4.11)	Third Supplemental Indenture, dated as of November 30, 2017, between NiSource Inc. and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.2 to the NiSource Inc. Form 8-K filed on December 1, 2017).
(4.12)	Second Supplemental Indenture, dated as of February 12, 2018, between Northern Indiana Public Service Company and The Bank of New York Mellon, solely as successor trustee under the Indenture dated as of March 1, 1988 between the Company and Manufacturers Hanover Trust Company, as original trustee. (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 10-Q filed on May 2, 2018).
(4.13)	Third Supplemental Indenture, dated as of June 11, 2018, by and between NiSource Inc. and The Bank of New York Mellon, as trustee (including form of 3.650% Notes due 2023) (incorporated by reference to Exhibit 4.1 of the NiSource Inc. Form 8-K filed on June 12, 2018).
(4.14)	Deposit Agreement, dated as of December 5, 2018, among NiSource, Inc., Computershare Inc. and Computershare Trust Company, N.A., acting jointly as depositary, and the holders from time to time of the depositary receipts described therein (incorporated by reference to Exhibit 4.1 of the NiSource Inc. Form 8-K filed on December 6, 2018).
(4.15)	Form of Depositary Receipt (incorporated by reference to Exhibit 4.1 of the NiSource Inc. Form 8-K filed on December 6, 2018).
(4.16)	Amended and Restated Deposit Agreement, dated as of December 27, 2018, among NiSource, Inc., Computershare Inc. and Computershare Trust Company, N.A., acting jointly as depositary, and the holders from time to time of the depositary receipts described therein (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on December 27, 2018).
(4.17)	Form of Depositary Receipt (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on December 27, 2018).
(4.18)	Form of 2.950% Notes due 2029 (incorporated by reference to Exhibit 4.1 to NiSource Inc. Form 8-K filed on August 12, 2019).

(4.19) Amended and Restated NiSource Inc. Employee Stock Purchase Plan (incorporated by reference to Exhibit C to the Registrant's Definitive Proxy Statement on Schedule 14A, filed with the Commission on April 1, 2019).

(4.20) Description of NiSource Inc.'s Securities Registered Under Section 12 of the Exchange Act. (incorporated by reference to Exhibit 4.20 of the NiSource Form 10-K filed on February 28, 2020)

(4.21) Form of 3.600% Notes due 2030 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on April 8, 2020).

(4.22) Form of 0.950% Notes due 2025 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on August 18, 2020).

(4.23) Form of 1.700% Notes due 2031(incorporated by reference to Exhibit 4.2 to the NiSource Inc. Form 8-K filed on August 18, 2020).

(4.24) Purchase Contract and Pledge Agreement, dated April 19, 2021, between NiSource Inc. and U.S. Bank National Association, in its capacity as the purchase contract agent, collateral agent, custodial agent and securities intermediary (incorporated by reference to Exhibit 4.1 of the NiSource Inc. Form 8-K filed on April 19, 2021).

(4.25) Form of Series A Corporate Units Certificate (incorporated by reference to Exhibit 4.1 of the NiSource Inc. Form 8-K filed on April 19, 2021).

(4.26) Form of Series A Treasury Units Certificate (incorporated by reference to Exhibit 4.1 of the NiSource Inc. Form 8-K filed on April 19, 2021).

(4.27) Form of Series A Cash Settled Units Certificate (incorporated by reference to Exhibit 4.1 of the NiSource Inc. Form 8-K filed on April 19, 2021).

(4.28) Form of Series C Mandatory Convertible Preferred Stock Certificate (incorporated by reference to Exhibit 3.1 of the NiSource Inc. Form 8-K filed on April 19, 2021).

(4.29) Form of 5.000% Notes due 2052 (incorporated by reference to Exhibit 4.1 of the NiSource Inc. Form 8-K filed on June 10, 2022).

(10.1) 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit B to the NiSource Inc. Definitive Proxy Statement to Stockholders for the Annual Meeting held on May 11, 2010, filed on April 2, 2010).*

(10.2) First Amendment to the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.2 to the NiSource Inc. Form 10-K filed on February 18, 2014.)*

(10.3) 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit C to the NiSource Inc. Definitive Proxy Statement to Stockholders for the Annual Meeting held on May 12, 2015, filed on April 7, 2015).*

(10.4) Second Amendment to the NiSource Inc. 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 8-K filed October 23, 2015.)*

(10.5) Form of Amended and Restated 2013 Performance Share Agreement effective on implementation of the spin-off on July 1, 2015, (under the 2010 Omnibus Incentive Plan)(incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 10-Q filed on November 3, 2015).*

(10.6) Form of Amended and Restated 2014 Performance Share Agreement effective on the implementation of the spin-off on July 1, 2015, (under the 2010 Omnibus Incentive Plan)(incorporated by reference to Exhibit 10.2 to the NiSource Inc. Form 10-Q filed on November 3, 2015).*

(10.7) Form of Amendment to Restricted Stock Unit Award Agreement related to Vested but Unpaid NiSource Restricted Stock Unit Awards for Nonemployee Directors of NiSource entered into as of July 13, 2015 (incorporated by reference to Exhibit 10.3 to the NiSource Inc. Form 10-Q filed on November 3, 2015).*

(10.8) NiSource Inc. Nonemployee Director Retirement Plan, as amended and restated effective May 13, 2008 (incorporated by reference to Exhibit 10.2 to the NiSource Inc. Form 10-K filed on February 27, 2009).*

(10.9) Supplemental Life Insurance Plan effective January 1, 1991, as amended, (incorporated by reference to Exhibit 2 to the NIPSCO Industries, Inc. Form 8-K filed on March 25, 1992).*

(10.10)	Revised Form of Change in Control and Termination Agreement (incorporated by reference to Exhibit 10.2 to the NiSource Inc. Form 8-K filed on October 23, 2015.)*
(10.11)	Form of Restricted Stock Agreement under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.18 to the NiSource Inc. Form 10-K filed on February 28, 2011).*
(10.12)	Form of Restricted Stock Unit Award Agreement for Non-employee directors under the Non-employee Director Stock Incentive Plan (incorporated by reference to Exhibit 10.19 to the NiSource Inc. Form 10-K filed on February 28, 2011).*
(10.13)	Form of Restricted Stock Unit Award Agreement for Nonemployee Directors under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.1 to NiSource Inc. Form 10-Q filed on August 2, 2011).*
(10.14)	Form of Restricted Stock Unit Award Agreement under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.17 to the NiSource Inc. Form 10-K filed on February 22, 2017).*
(10.15)	Form of Restricted Stock Unit Award Agreement for Nonemployee Directors under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.18 to the NiSource Inc. Form 10-K filed on February 22, 2017). *
(10.16)	Amended and Restated NiSource Inc. Executive Deferred Compensation Plan effective November 1, 2012 (incorporated by reference to Exhibit 10.21 to the NiSource Inc. Form 10-K filed on February 19, 2013).*
(10.17)	NiSource Inc. Executive Severance Policy, as amended and restated, effective January 1, 2015 (incorporated by reference to Exhibit 10.21 to the NiSource Inc. Form 10-K filed on February 18, 2015).*
(10.18)	Note Purchase Agreement, dated as of August 23, 2005, by and among NiSource Finance Corp., as issuer, NiSource Inc., as guarantor, and the purchasers named therein (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Current Report on Form 8-K filed on August 26, 2005).
(10.19)	Amendment No. 1, dated as of November 10, 2008, to the Note Purchase Agreement by and among NiSource Finance Corp., as issuer, NiSource Inc., as guarantor, and the purchasers whose names appear on the signature page thereto (incorporated by reference to Exhibit 10.30 to the NiSource Inc. Form 10-K filed on February 27, 2009).
(10.20)	Letter Agreement, dated as of March 17, 2015, by and between NiSource Inc. and Donald Brown. (incorporated by reference Exhibit 10.1 to the NiSource Inc. Form 10-Q filed on April 30, 2015).*
(10.21)	Letter Agreement, dated as of February 23, 2016, by and between NiSource Inc. and Pablo A. Vegas. (incorporated by reference Exhibit 10.29 to the NiSource Inc. Form 10-K filed on February 22, 2017).*
(10.22)	Employee Matters Agreement, dated as of June 30, 2015, by and between NiSource Inc. and Columbia Pipeline Group, Inc. (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 8-K filed on July 2, 2015).
(10.23)	Form of Change in Control and Termination Agreement (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 10-Q filed on August 2, 2017).*
(10.24)	Form of Performance Share Award Agreement under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.33 to the NiSource Form 10-K filed on February 20, 2018).*
(10.25)	Form of Restricted Stock Unit Award Agreement under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.34 to the NiSource Form 10-K filed on February 20, 2018).*
(10.26)	Common Stock Subscription Agreement, dated as of May 2, 2018, by and among NiSource Inc. and the purchasers named therein (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on May 2, 2018).
(10.27)	Registration Rights Agreement, dated as of May 2, 2018, by and among NiSource Inc. and the purchasers named therein (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 8-K filed on May 2, 2018).
(10.28)	Purchase Agreement, dated as of June 6, 2018, by and among NiSource Inc. and Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC and MUFG Securities Americas Inc., as representatives, relating to the 5.650% Series A Preferred Stock (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on June 12, 2018).

(10.29) Purchase Agreement, dated as of June 6, 2018, by and among NiSource Inc. and Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC and MUFG Securities Americas Inc., as representatives, relating to the 3.650% Notes due 2023 (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 8-K filed on June 12, 2018).

(10.30) Registration Rights Agreement, dated as of June 11, 2018, by and among NiSource Inc. and Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC and MUFG Securities Americas Inc., as representatives, relating to the 5.650% Series A Preferred Stock (incorporated by reference to Exhibit 10.3 of the NiSource Inc. Form 8-K filed on June 12, 2018).

(10.31) Registration Rights Agreement, dated as of June 11, 2018, by and among NiSource Inc. and Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC and MUFG Securities Americas Inc., as representatives, relating to the 3.650% Notes due 2023 (incorporated by reference to Exhibit 10.4 of the NiSource Inc. Form 8-K filed on June 12, 2018).

(10.32) Form of 2019 Performance Share Award Agreement under the 2010 Omnibus Incentive Plan. (incorporated by reference to Exhibit 10.45 of the NiSource Inc. Form 10-K filed on February 20, 2019).*

(10.33) Amended and Restated NiSource Inc. Employee Stock Purchase Plan adopted as of February 1, 2019 (incorporated by reference to Exhibit C to the NiSource Inc. Definitive Proxy Statement to Stockholders for the Annual Meeting to be held on May 7, 2019, filed on April 1, 2019).

(10.34) Form of Performance Share Award Agreement (incorporated by reference to Exhibit 10.39 of the NiSource Form 10-K filed on February 28, 2020).*

(10.35) Form of Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.40 of the NiSource Form 10-K filed on February 28, 2020). *

(10.36) Form of Cash-Based Award Agreement (incorporated by reference to Exhibit 10.41 of the NiSource Form 10-K filed on February 28, 2020). *

(10.37) Columbia Gas of Massachusetts Plea Agreement dated February 26, 2020 (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 8-K filed on February 27, 2020).

(10.38) NiSource Deferred Prosecution Agreement dated February 26, 2020 (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on February 27, 2020).

(10.39) 2020 Omnibus Incentive Plan (incorporated by reference to Exhibit A to the NiSource Inc. Definitive Proxy Statement to Stockholders for the Annual Meeting held on May 19, 2020, filed on April 13, 2020).*

(10.40) Settlement Agreement, dated July 2, 2020, by and among Bay State Gas Company d/b/a Columbia Gas of Massachusetts, NiSource Inc., Eversource Gas Company of Massachusetts, Eversource Energy, the Massachusetts Attorney General's Office, the Massachusetts Department of Energy Resources the Low-Income Weatherization and Fuel Assistance Program Network (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on July 6, 2020).

(10.41) Form of Restricted Stock Unit Award Agreement for Nonemployee Directors under the 2020 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 10-Q filed on August 5, 2020).*

(10.42) Addendum to Plea Agreement filed on or about June 21, 2020 in the United States District Court for the District of Massachusetts (incorporated by reference to Exhibit 10.4 of the NiSource Inc. Form 10-Q filed on August 5, 2020).

(10.43) Letter Agreement by and among NiSource Inc., Bay State Gas Company d/b/a Columbia Gas of Massachusetts and Eversource Energy Relating to Asset Purchase Agreement, dated October 9, 2020 (incorporated by reference to Exhibit 10.3 to the NiSource Inc. Form 10-Q filed on November 2, 2020).***

(10.44) NiSource Inc. Supplemental Executive Retirement Plan, as amended and restated effective November 1, 2020 (incorporated by reference to Exhibit 10.4 to the NiSource Inc. Form 10-Q filed on November 2, 2020).*

(10.45) Pension Restoration Plan for NiSource Inc. and Affiliates, as amended and restated effective November 1, 2020 (incorporated by reference to Exhibit 10.5 to the NiSource Inc. Form 10-Q filed on November 2, 2020).

(10.46) Savings Restoration Plan for NiSource Inc. and Affiliates, as amended and restated effective November 1, 2020 (incorporated by reference to Exhibit 10.6 to the NiSource Inc. Form 10-Q filed on November 2, 2020).*

(10.47)	NiSource Inc. Executive Severance Policy, as amended and restated effective October 19, 2020 (incorporated by reference to Exhibit 10.7 to the NiSource Inc. Form 10-Q filed on November 2, 2020).*
(10.48)	NiSource Next Voluntary Separation Program, effective as of August 5, 2020 (incorporated by reference to Exhibit 10.8 to the NiSource Inc. Form 10-Q filed on November 2, 2020).*
(10.49)	Letter Agreement dated October 19, 2020 by and between NiSource Inc. and Carrie Hightman (incorporated by reference to Exhibit 10.9 to the NiSource Inc. Form 10-Q filed on November 2, 2020).*
(10.50)	Amendment to Settlement Agreement by and among Bay State Gas Company d/b/a Columbia Gas of Massachusetts, NiSource Inc., Eversource Gas Company of Massachusetts, Eversource Energy, the Massachusetts Attorney General's Office, the Massachusetts Department of Energy Resources and the Low-Income Weatherization and Fuel Assistance Program Network, dated September 29, 2020 (incorporated by reference to Exhibit 10.2 to the NiSource Inc. Form 10-Q filed on November 2, 2020).
(10.51)	Form of Restricted Stock Unit Award Agreement. (incorporated by reference to Exhibit 10.53 to the NiSource Inc. Form 10-K filed on February 17, 2021).*
(10.52)	Form of Performance Share Unit Award Agreement. (incorporated by reference to Exhibit 10.54 to the NiSource Inc. Form 10-K filed on February 17, 2021).*
(10.53)	Form of Special Performance Share Unit Award Agreement. (incorporated by reference to Exhibit 10.55 to the NiSource Inc. Form 10-K filed on February 17, 2021).*
(10.54)	Sixth Amended and Restated Revolving Credit Agreement, dated as of February 18, 2022, among NiSource Inc., as Borrower, the Lenders party thereto, Barclays Bank PLC, as Administrative Agent, JPMorgan Chase Bank, N.A. and MUFG Bank, Ltd., as Co-Syndication Agents, Credit Suisse AG, New York Branch, Wells Fargo Bank, National Association, and Bank of America, National Association, as Co-Documentation Agents, Barclays Bank PLC and MUFG Bank, Ltd., as Co-Sustainability Structuring Agents, and Barclays Bank PLC, JPMorgan Chase Bank, N.A. MUFG Bank, Ltd., Credit Suisse Loan Funding LLC, Wells Fargo Securities, LLC, and BofA Securities, Inc., as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on February 18, 2022).
(10.55)	First Amendment to the NiSource Inc. 2020 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 10-Q filed on May 4, 2022)
(10.56)	Credit Agreement, dated as of December 20, 2022, among NiSource Inc., as Borrower, the lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent, PNC Capital Markets LLC, as Syndication Agent, Bank of America, N.A. and Wells Fargo Bank, N.A., as Co-Documentation Agents and JPMorgan Chase Bank, N.A., PNC Capital Markets LLC, Bank of America, N.A. and Wells Fargo Securities, LLC, as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on December 20, 2022)
(10.57)	Form of Restricted Stock Unit Award Agreement.* **
(10.58)	Form of Performance Share Unit Award Agreement.* **
(10.59)	Form of Restricted Stock Unit Award Agreement.* **
(10.60)	Form of Performance Share Unit Award Agreement.* **
(21)	List of Subsidiaries.**
(23)	Consent of Deloitte & Touche LLP.**
(31.1)	Certification of Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.**
(31.2)	Certification of Chief Financial Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.**
(32.1)	Certification of Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).**
(32.2)	Certification of Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).**
(101.INS)	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document. **

(101.SCH) Inline XBRL Schema Document.**

(101.CAL) Inline XBRL Calculation Linkbase Document.**

(101.LAB) Inline XBRL Labels Linkbase Document.**

(101.PRE) Inline XBRL Presentation Linkbase Document.**

(101.DEF) Inline XBRL Definition Linkbase Document.**

(104) Cover page Interactive Data File (formatted as inline XBRL, and contained in Exhibit 101.)

* Management contract or compensatory plan or arrangement of NiSource Inc.

** Exhibit filed herewith.

*** Schedules and exhibits have been omitted pursuant to Item 601(b)(2) of Regulation S-K. NiSource agrees to furnish supplementally a copy of any omitted schedules or exhibits to the SEC upon request.

References made to NIPSCO filings can be found at Commission File Number 001-04125. References made to NiSource Inc. filings made prior to November 1, 2000 can be found at Commission File Number 001-09779.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, hereunto duly authorized.

NiSource Inc.
(Registrant)

Date: February 22, 2023

By: /s/ LLOYD M. YATES
Lloyd M. Yates
President, Chief Executive Officer and Director
(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/ LLOYD M. YATES Lloyd M. Yates	President, Chief Executive Officer and Director (Principal Executive Officer)	Date: February 22, 2023
/s/ DONALD E. BROWN Donald E. Brown	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	Date: February 22, 2023
/s/ GUNNAR J. GODE Gunnar J. Gode	Vice President and Chief Accounting Officer (Principal Accounting Officer)	Date: February 22, 2023
/s/ KEVIN T. KABAT Kevin T. Kabat	Chairman of the Board	Date: February 22, 2023
/s/ PETER A. ALTABEF Peter A. Altabef	Director	Date: February 22, 2023
/s/ SONDRA L. BARBOUR Sondra L. Barbour	Director	Date: February 22, 2023
/s/ THEODORE H. BUNTING, JR. Theodore H. Bunting, Jr.	Director	Date: February 22, 2023
/s/ ERIC L. BUTLER Eric L. Butler	Director	Date: February 22, 2023
/s/ ARISTIDES S. CANDRIS Aristides S. Candris	Director	Date: February 22, 2023
/s/ DEBORAH A. HENRETTA Deborah A. Henretta	Director	Date: February 22, 2023
/s/ DEBORAH A.P. HERSMAN Deborah A. P. Hersman	Director	Date: February 22, 2023
/s/ MICHAEL E. JESANIS Michael E. Jesanis	Director	Date: February 22, 2023
/s/ WILLIAM D. JOHNSON William D. Johnson	Director	Date: February 22, 2023
/s/ CASSANDRA S. LEE Cassandra S. Lee	Director	Date: February 22, 2023

STOCKHOLDER INFORMATION

Forward-Looking Statements

This document contains “forward-looking statements,” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). Investors and prospective investors should understand that many factors govern whether any forward-looking statement contained herein will be or can be realized. Any one of those factors could cause actual results to differ materially from those projected. These forward-looking statements include, but are not limited to, statements concerning our plans, strategies, objectives, expected performance, expenditures, recovery of expenditures through rates, stated on either a consolidated or segment basis, and any and all underlying assumptions and other statements that are other than statements of historical fact. Expressions of future goals and expectations and similar expressions, including “may,” “will,” “should,” “could,” “would,” “aims,” “seeks,” “expects,” “plans,” “anticipates,” “intends,” “believes,” “estimates,” “predicts,” “potential,” “targets,” “forecast,” and “continue,” reflecting something other than historical fact are intended to identify forward-looking statements. All forward-looking statements are based on assumptions that management believes to be reasonable; however, there can be no assurance that actual results will not differ materially.

Factors that could cause actual results to differ materially from the projections, forecasts, estimates and expectations discussed in this document include, among other things, our ability to execute our business plan or growth strategy, including utility infrastructure investments; potential incidents and other operating risks associated with our business; our ability to adapt to, and manage costs related to, advances in technology; impacts related to our aging infrastructure; our ability to obtain sufficient insurance coverage and whether such coverage will protect us against significant losses; the success of our electric generation strategy; construction risks and natural gas costs and supply risks; fluctuations in demand from residential and commercial customers; fluctuations in the price of energy commodities and related transportation costs or an inability to obtain an adequate, reliable and cost-effective fuel supply to meet customer demands; the attraction and retention of a qualified, diverse workforce and ability to maintain good labor relations; our ability to manage new initiatives and organizational changes; the actions of activist stockholders; the performance of third-party suppliers and service providers; potential cybersecurity attacks; increased requirements and costs related to cybersecurity; any damage to our reputation; any remaining liabilities or impact related to the sale of the Massachusetts Business; the impacts of natural disasters, potential terrorist attacks or other catastrophic events; the physical impacts of climate change and the transition to a lower carbon future; our ability to manage the financial and operational risks related to achieving our carbon emission reduction goals, including our Net Zero Goal; our debt obligations; any changes to our credit rating or the credit rating of certain of our subsidiaries; any adverse effects related to our equity units; adverse economic and capital market conditions or increases in interest rates; inflation; recessions; economic regulation and the impact of regulatory rate reviews; our ability to obtain expected financial or regulatory outcomes; continuing and potential future impacts from the COVID-19 pandemic; economic conditions in certain industries; the reliability of customers and suppliers to fulfill their payment and contractual obligations; the ability of our subsidiaries to generate cash; pension funding obligations; potential impairments of goodwill; the outcome of legal and regulatory proceedings, investigations, incidents, claims and litigation; potential remaining liabilities related to the Greater Lawrence Incident; compliance with the agreements entered into with the U.S. Attorney’s Office to settle the U.S. Attorney’s Office’s investigation relating to the Greater Lawrence Incident; compliance with applicable laws, regulations and tariffs; compliance with environmental laws and the costs of associated liabilities; changes in taxation; and other matters set forth in Item 1, “Business,” Item 1A, “Risk Factors” and Part II, Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” of our Annual Report on Form 10-K for the fiscal year ended December 31, 2022, some of which risks are beyond our control. In addition, the relative contributions to profitability by each business segment, and the assumptions underlying the forward-looking statements relating thereto, may change over time.

All forward-looking statements are expressly qualified in their entirety by the foregoing cautionary statements. We undertake no obligation to, and expressly disclaim any such obligation to, update or revise any forward-looking statements to reflect changed assumptions, the occurrence of anticipated or unanticipated events or changes to the future results over time or otherwise, except as required by law.

Regulation G Disclosure Statement

This document includes financial results and guidance for NiSource with respect to net operating earnings available to common shareholders, which is a non-GAAP financial measure as defined by the Securities and Exchange Commission’s (SEC) Regulation G. The company includes this measure because management believes it permits investors to view the company’s performance using the same tools that management uses and to better evaluate the company’s ongoing business performance. With respect to such guidance, it should be noted that there will likely be a difference between this measure and its GAAP equivalent due to various factors, including, but not limited to, fluctuations in weather, the impact of asset sales and impairments, and other items included in GAAP results. The company is not able to estimate the impact of such factors on GAAP earnings and, as such, is not providing earnings guidance on a GAAP basis. In addition, the company is not able to provide a reconciliation of its non-GAAP net operating earnings guidance to its GAAP equivalent without unreasonable efforts.

Investor Relations
(219) 647-5688

Media Relations
media@nisource.com

Anticipated Dividend Record and Payment Dates* (NiSource Common Stock)

Record Date	Payment Date
02/07/23	02/17/23
04/28/23	05/19/23
07/31/23	08/18/23
10/31/23	11/20/23
02/05/24	02/20/24

Common Stock Dividend Declared
On February 17, 2023, the company paid a quarterly dividend of $0.25 per share to stockholders of record as of the close of business on February 7, 2023, equivalent to $1.00 per share on an annual basis.

Stockholder Services
Questions about stockholder accounts, stock certificates, transfer of shares, dividend payments, automatic dividend reinvestment and stock purchase plan, and electronic deposit may be directed to Computershare at the following:

Computershare
c/o Shareholder Services
P.O. Box 43078
Providence RI 02940-3078
(888) 884-7790
- TDD for Hearing Impaired: (800) 231-5469
- Foreign Stockholders: (201) 680-6578
- TDD Foreign Stockholders: (201) 680-6610
- Computershare.com/investor

*DIVIDENDS ARE SUBJECT TO BOARD APPROVAL.

Investor and Financial Information
Financial analysts and investment professionals should direct written and telephone inquiries to NiSource Investor Relations, 801 East 86th Avenue, Merrillville, Indiana 46410 or (219) 647-5688. Copies of NiSource’s financial reports are available at NiSource.com, or by writing or calling the Investor Relations department at the address or phone number listed above.

Stock Listing
NiSource Inc common stock is listed on the New York Stock Exchange under the ticker symbol “NI.”

Independent Registered Public Accounting Firm
Deloitte & Touche LLP

Sustainability
While addressed in the 2021 Integrated Annual Report, additional details on sustainability and environmental, social and governance (ESG) issues and related policies can be found under the Sustainability tab at NiSource.com.

Board of Directors
Communications with the Board of Directors may be made generally, to any director individually, to the non-management directors as a group or the lead director of the non-management group by writing to the following address:

NiSource Inc.
Attention: Board of Directors, Board Member,
non-management directors or Chairman
c/o Corporate Secretary
801 East 86th Avenue
Merrillville, Indiana 46410

Corporate Governance
At NiSource.com, shareholders can view the company’s corporate governance guidelines, code of business conduct, political spending policy and charters of all board-level committees. Copies of these documents are available to shareholders without charge upon written request to Corporate Secretary at the above address.

COMPANY LOCATIONS

Corporate Headquarters
NiSource Inc.
801 E. 86th Avenue
Merrillville, Indiana 46410
(219) 647-5990
NiSource.com

NiSource Corporate Services
290 W. Nationwide Boulevard
Columbus, Ohio 43215
(614) 460-6000
NiSource.com

Columbia Gas of Kentucky
2001 Mercer Road
Lexington, Kentucky 40511
Emergency: (800) 432-9515
Customer Care: (800) 432-9345
ColumbiaGasKY.com

Columbia Gas of Maryland
121 Champion Way
Canonsburg, Pennsylvania 15317
Emergency: (888) 460-4332
Customer Care: (888) 460-4332
ColumbiaGasMD.com

Columbia Gas of Ohio
290 W. Nationwide Boulevard
Columbus, Ohio 43215
Emergency: (800) 344-4077
Customer Care: (800) 344-4077
ColumbiaGasOhio.com

Columbia Gas of Pennsylvania
121 Champion Way
Canonsburg, Pennsylvania 15317
Emergency: (888) 460-4332
Customer Care: (888) 460-4332
ColumbiaGasPA.com

Columbia Gas of Virginia
1809 Coyote Drive
Chester, Virginia 02383
Emergency: (800) 544-5606
Customer Care: (800) 543-8911
ColumbiaGasVA.com

NIPSCO
801 E. 86th Avenue
Merrillville, Indiana 46410
Customer Care: (800) 464-7726
Gas Emergency: (800) 634-3524
Electric Emergency: (800) 464-7726
NIPSCO.com

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2022

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ___________ to___________

Commission file number 1-38681	Commission file number 1-15973
NORTHWEST NATURAL HOLDING COMPANY	**NORTHWEST NATURAL GAS COMPANY**
(Exact name of registrant as specified in its charter)	(Exact name of registrant as specified in its charter)
Oregon **82-4710680**	**Oregon** **93-0256722**
(State or other jurisdiction of incorporation or organization) (I.R.S. Employer Identification No.)	(State or other jurisdiction of incorporation or organization) (I.R.S. Employer Identification No.)
250 S.W. Taylor Street **Portland** **Oregon** **97204**	**250 S.W. Taylor Street** **Portland** **Oregon** **97204**
(Address of principal executive offices) (Zip Code)	(Address of principal executive offices) (Zip Code)
Registrant's telephone number, including area code: **(503) 226-4211**	Registrant's telephone number, including area code: **(503) 226-4211**

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of each class	Trading Symbol	Name of each exchange on which registered
Northwest Natural Holding Company	Common Stock	NWN	New York Stock Exchange
Northwest Natural Gas Company	None	None	None

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

NORTHWEST NATURAL HOLDING COMPANY Yes ☒ No ☐ NORTHWEST NATURAL GAS COMPANY Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

NORTHWEST NATURAL HOLDING COMPANY Yes ☐ No ☒ NORTHWEST NATURAL GAS COMPANY Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

NORTHWEST NATURAL HOLDING COMPANY Yes ☒ No ☐ NORTHWEST NATURAL GAS COMPANY Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

NORTHWEST NATURAL HOLDING COMPANY Yes ☒ No ☐ NORTHWEST NATURAL GAS COMPANY Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

NORTHWEST NATURAL HOLDING COMPANY		NORTHWEST NATURAL GAS COMPANY	
Large Accelerated Filer	☒	Large Accelerated Filer	☐
Accelerated Filer	☐	Accelerated Filer	☐
Non-accelerated Filer	☐	Non-accelerated Filer	☒
Smaller Reporting Company	☐	Smaller Reporting Company	☐
Emerging Growth Company	☐	Emerging Growth Company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report.

NORTHWEST NATURAL HOLDING COMPANY Yes ☒ No ☐ NORTHWEST NATURAL GAS COMPANY Yes ☐ No ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

NORTHWEST NATURAL HOLDING COMPANY Yes ☐ No ☒ NORTHWEST NATURAL GAS COMPANY Yes ☐ No ☒

As of the end of the second quarter of 2022, the aggregate market value of the shares of Common Stock of Northwest Natural Holding Company (based upon the closing price of these shares on the New York Stock Exchange on June 30, 2022) held by non-affiliates was $1,825,498,356.

At February 16, 2023, 35,539,262 shares of Northwest Natural Holding Company's Common Stock (the only class of Common Stock) were outstanding. All shares of Northwest Natural Gas Company's Common Stock (the only class of Common Stock) outstanding were held by Northwest Natural Holding Company.

This combined Form 10-K is separately filed by Northwest Natural Holding Company and Northwest Natural Gas Company. Information contained in this document relating to Northwest Natural Gas Company is filed by Northwest Natural Holding Company and separately by Northwest Natural Gas Company. Northwest Natural Gas Company makes no representation as to information relating to Northwest Natural Holding Company or its subsidiaries, except as it may relate to Northwest Natural Gas Company and its subsidiaries.

Northwest Natural Gas Company meets the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K and is therefore filing this report with the reduced disclosure format.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Northwest Natural Holding Company's Proxy Statement, to be filed in connection with the 2023 Annual Meeting of Shareholders, are incorporated by reference in Part III.

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GLOSSARY OF TERMS AND ABBREVIATIONS

ACC	Arizona Corporation Commission; the entity that regulates NW Holdings' regulated water and wastewater businesses in Arizona with respect to rates and terms of service, among other matters
AFUDC	Allowance for Funds Used During Construction
AOCI / AOCL	Accumulated Other Comprehensive Income (Loss)
AMP	Arrearage Management Program
ASC	Accounting Standards Codification
ASU	Accounting Standards Update as issued by the FASB
Average Weather	The 25-year average of heating degree days based on temperatures established in our last Oregon general rate case
Bcf	Billion cubic feet, a volumetric measure of natural gas, where one Bcf is roughly equal to 10 million therms
CAP	Compliance Assurance Process with the Internal Revenue Service
CCA	Climate Commitment Act enacted by the State of Washington
CNG	Compressed Natural Gas
CODM	Chief Operating Decision Maker, which for accounting purposes is defined as an individual or group of individuals responsible for the allocation of resources and assessing the performance of the entity's business units
Core NGD Customers	Residential, commercial, and industrial customers receiving firm service from the Natural Gas Distribution business
Cost of Gas	The delivered cost of natural gas sold to customers, including the cost of gas purchased or withdrawn/produced from storage inventory or reserves, gains and losses from gas commodity hedges, pipeline demand costs, seasonal demand cost balancing adjustments, renewable thermal certificate costs and regulatory gas cost deferrals
CPP	Climate Protection Program established by the Environmental Quality Commission of the Oregon Department of Environmental Quality
Decoupling	A natural gas billing rate mechanism, also referred to as a conservation tariff, which is designed to allow a utility to encourage residential and small commercial customers to conserve energy
Degree Day	The number of degrees that the average outdoor temperature falls below or exceeds a base value in a given period of time
Demand Cost	A component in NGD customer rates representing the cost of securing firm pipeline capacity, whether the capacity is used or not
ECRM	Environmental Cost Recovery Mechanism, a billing rate mechanism for recovering prudently incurred environmental site remediation costs allocable to Washington customers through NGD customer billings
EE/CA	Engineering Evaluation / Cost Analysis
Encana	Encana Oil & Gas (USA) Inc.
Energy Corp	Northwest Energy Corporation, a wholly-owned subsidiary of Northwest Natural Gas Company
EPA	Environmental Protection Agency
EPS	Earnings per share
ERP	Enterprise Resource Planning
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission; the entity regulating interstate storage services offered by the Mist gas storage facility
Firm Service	Natural gas service offered to customers under contracts or rate schedules that will not be disrupted to meet the needs of other customers
FMBs	First Mortgage Bonds
General Rate Case	A periodic filing with state or federal regulators to establish billing rates for utility customers
GHG	Greenhouse gases
GTN	Gas Transmission Northwest, LLC which owns a transmission pipeline serving California and the Pacific Northwest
Interruptible Service	Natural gas service offered to customers (usually large commercial or industrial users) under contracts or rate schedules that allow for interruptions when necessary to meet the needs of firm service customers

Interstate Storage Services	The portion of the Mist gas storage facility not used to serve NGD customers, instead serving utilities, gas marketers, electric generators, and large industrial users
IPUC	Public Utility Commission of Idaho; the entity that regulates NW Holdings' regulated water businesses in Idaho with respect to rates and terms of service, among other matters
IRA	Inflation Reduction Act of 2022
IRP	Integrated Resource Plan
KB	Kelso-Beaver Pipeline, of which 10% is owned by KB Pipeline Company, a subsidiary of NNG Financial Corporation
LIBOR	London Interbank Offered Rate
LNG	Liquefied Natural Gas, the cryogenic liquid form of natural gas. To reach a liquid form at atmospheric pressure, natural gas must be cooled to approximately negative 260 degrees Fahrenheit
LTIP	Long Term Incentive Plan
Moody's	Moody's Investors Service, Inc., credit rating agency
NAV	Net Asset Value
NGD	Natural Gas Distribution, a segment of Northwest Natural Holding Company and Northwest Natural Gas Company that provides regulated natural gas distribution services to residential, commercial, and industrial customers in Oregon and Southwest Washington
NGD Margin	A financial measure used by NW Natural's CODM consisting of NGD operating revenues less the associated cost of gas, revenue taxes, and environmental recoveries
NNG Financial	NNG Financial Corporation, a wholly-owned subsidiary of NW Holdings
NOL	Net Operating Loss
NRD	Natural Resource Damages
NW Holdings	Northwest Natural Holding Company
NW Natural	Northwest Natural Gas Company, a wholly-owned subsidiary of NW Holdings
NW Natural Renewables	NW Natural Renewables Holdings, LLC, a wholly-owned subsidiary of NW Holdings
NWN Energy	NW Natural Energy, LLC, a wholly-owned subsidiary of NW Holdings
NWN Gas Reserves	NWN Gas Reserves LLC, a wholly-owned subsidiary of Energy Corp
NWN Gas Storage	NW Natural Gas Storage, LLC, a wholly-owned subsidiary of NWN Energy
NWN Water	NW Natural Water Company, LLC, a wholly-owned subsidiary of NW Holdings
ODEQ	Oregon Department of Environmental Quality
OPEIU	Office and Professional Employees International Union Local No. 11, AFL-CIO, the Union which represents NW Natural's bargaining unit employees
OPUC	Public Utility Commission of Oregon; the entity that regulates our Oregon natural gas and regulated water businesses with respect to rates and terms of service, among other matters; the OPUC also regulates the Mist gas storage facility's intrastate storage services
PBGC	Pension Benefit Guaranty Corporation
PGA	Purchased Gas Adjustment, a regulatory mechanism primarily used to adjust natural gas customer rates to reflect changes in the forecasted cost of gas and differences between forecasted and actual gas costs from the prior year
PHMSA	U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration
PRP	Potentially Responsible Parties
PUCT	Public Utility Commission of Texas; the entity that regulates NW Holdings' regulated water and wastewater businesses in Texas with respect to rates and terms of service, among other matters
RI/FS	Remedial Investigation / Feasibility Study
RNG	Renewable Natural Gas, a source of natural gas derived from organic materials which may be captured, refined, and distributed on natural gas pipeline systems
RNG Hold Co	NW Natural RNG Holding Company, LLC, a wholly-owned subsidiary of Northwest Natural Gas Company
ROD	Record of Decision
ROE	Return on Equity, a measure of corporate profitability, calculated as net income or loss divided by average common equity. Authorized ROE refers to the equity rate approved by a regulatory agency for use in determining utility revenue requirements
ROR	Rate of Return, a measure of return on utility rate base. Authorized ROR refers to the rate of return approved by a regulatory agency and is generally discussed in the context of ROE and capital structure
RSU	Restricted Stock Unit

RTC	Renewable Thermal Certificate
S&P	Standard & Poor's Financial Services LLC, a credit rating agency and a subsidiary of S&P Global Inc.
Sales Service	Service provided whereby a customer purchases both natural gas commodity supply and transportation from the NGD business
SEC	U.S. Securities and Exchange Commission
SOFR	Secured Overnight Financing Rate
SRRM	Site Remediation and Recovery Mechanism, a billing rate mechanism for recovering prudently incurred environmental site remediation costs allocable to Oregon through NGD customer billings, subject to an earnings test
Therm	The basic unit of natural gas measurement, equal to one hundred thousand British thermal units
Transportation Service	Service provided whereby a customer purchases natural gas directly from a supplier but pays the utility to transport the gas over its distribution system to the customer's facility
TSA	Transportation Security Administration
U.S. GAAP	Accounting principles generally accepted in the United States of America
WARM	An Oregon billing rate mechanism applied to natural gas residential and commercial customers to adjust for temperature variances from average weather
WUTC	Washington Utilities and Transportation Commission, the entity that regulates our Washington natural gas and regulated water businesses with respect to rates and terms of service, among other matters

FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995, which are subject to the safe harbors created by such Act. Forward-looking statements can be identified by words such as anticipates, assumes, may, intends, plans, projects, seeks, believes, estimates, expects, will, could, and similar references (including the negatives thereof) to future periods, although not all forward-looking statements contain these words. Examples of forward-looking statements include, but are not limited to, statements regarding the following:

- plans, projections and predictions;
- objectives, goals, visions or strategies;
- assumptions, generalizations and estimates;
- ongoing continuation of past practices or patterns;
- future events or performance;
- trends;
- risks;
- uncertainties;
- timing and cyclicality;
- economic conditions, including impacts of inflation and interest rates, recessionary risk, and general economic uncertainty;
- earnings and dividends;
- capital expenditures and allocation;
- capital markets or access to capital;
- capital or organizational structure;
- matters related to climate change and our role in decarbonization or a low-carbon future;
- renewable natural gas, environmental attributes related thereto, and hydrogen;
- our strategy to reduce greenhouse gas emissions and the efficacy of communicating that strategy to shareholders, investors, stakeholders and communities;
- the policies and priorities of the current presidential administration and U.S. Congress;
- growth;
- customer rates;
- pandemic and related illness or quarantine, including COVID-19 and related variants and subvariants, and, economic conditions related thereto or resulting therefrom;
- labor relations and workforce succession;
- commodity costs;
- desirability and cost competitiveness of natural gas;
- gas reserves;
- operational performance and costs;
- energy policy, infrastructure and preferences;
- public policy approach and involvement;
- efficacy of derivatives and hedges;
- liquidity, financial positions, and planned securities issuances;
- valuations;
- project and program development, expansion, or investment;
- business development efforts, including new business lines such as unregulated renewable natural gas, and acquisitions and integration thereof;
- implementation and execution of our water strategy;
- pipeline capacity, demand, location, and reliability;
- adequacy of property rights and operations center development;
- technology implementation and cybersecurity practices;
- competition;
- procurement and development of gas (including renewable natural gas) and water supplies;
- estimated expenditures, supply chain and third party availability and impairment;
- supply chain disruptions;
- costs of compliance, and our ability to include those costs in rates;
- customers bypassing our infrastructure;
- credit exposures;
- uncollectible account amounts;
- rate or regulatory outcomes, recovery or refunds, and the availability of public utility commissions to take action;
- impacts or changes of executive orders, laws, rules and regulations, or legal challenges related thereto, including the Inflation Reduction Act or other energy climate related legislation;
- tax liabilities or refunds, including effects of tax legislation;
- levels and pricing of gas storage contracts and gas storage markets;
- outcomes, timing and effects of potential claims, litigation, regulatory actions, and other administrative matters;
- projected obligations, expectations and treatment with respect to, and the impact of new legislation on, retirement plans;
- international, federal, state, and local efforts to regulate, in a variety of ways, greenhouse gas emissions, and the effects of those efforts;

- geopolitical factors, such as the Russia/Ukraine conflict;
- availability, adequacy, and shift in mix, of gas and water supplies;
- effects of new or anticipated changes in critical accounting policies or estimates;
- approval and adequacy of regulatory deferrals;
- effects and efficacy of regulatory mechanisms; and
- environmental, regulatory, litigation and insurance costs and recoveries, and timing thereof.

Forward-looking statements are based on our current expectations and assumptions regarding our business, the economy, and other future conditions. Because forward-looking statements relate to the future, they are subject to inherent uncertainties, risks, and changes in circumstances that are difficult to predict. Our actual results may differ materially from those contemplated by the forward-looking statements. We therefore caution you against relying on any of these forward-looking statements. They are neither statements of historical fact nor guarantees or assurances of future performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements are discussed at Item 1A., "Risk Factors" of Part I and Item 7. and Item 7A., "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Quantitative and Qualitative Disclosures About Market Risk", respectively, of Part II of this report.

Any forward-looking statement made in this report speaks only as of the date on which it is made. Factors or events that could cause actual results to differ may emerge from time to time, and it is not possible for us to predict all of them. We undertake no obligation to publicly update any forward-looking statement, whether as a result of new information, future developments or otherwise, except as may be required by law.

PART I

FILING FORMAT

This annual report on Form 10-K is a combined report being filed by two separate registrants: Northwest Natural Holding Company (NW Holdings), and Northwest Natural Gas Company (NW Natural). Except where the content clearly indicates otherwise, any reference in the report to "we," "us" or "our" is to the consolidated entity of NW Holdings and all of its subsidiaries, including NW Natural, which is a distinct SEC registrant that is a wholly-owned subsidiary of NW Holdings. Each of NW Holdings' subsidiaries is a separate legal entity with its own assets and liabilities. Information contained herein relating to any individual registrant or its subsidiaries is filed by such registrant on its own behalf. Each registrant makes representations only as to itself and its subsidiaries and makes no other representation whatsoever as to any other company.

Item 8 in this Annual Report on Form 10-K includes separate financial statements (i.e. balance sheets, statements of comprehensive income, statements of cash flows, and statements of equity) for NW Holdings and NW Natural, in that order. References in this discussion to the "Notes" are to the Notes to the Consolidated Financial Statements in Item 8 of this report. The Notes to the Consolidated Financial Statements are presented on a combined basis for both entities except where expressly noted otherwise. All Items other than Item 8 are combined for the reporting companies.

ITEM 1. BUSINESS

OVERVIEW

NW Holdings is a holding company headquartered in Portland, Oregon and owns NW Natural, NW Natural Water Company, LLC (NWN Water), NW Natural Renewables Holdings, LLC, a non-regulated subsidiary established to pursue non-regulated renewable natural gas activities, and other businesses and activities. NW Natural is NW Holdings’ largest subsidiary.

NW Natural distributes natural gas to residential, commercial, and industrial customers in Oregon and southwest Washington. NW Natural and its predecessors have supplied gas service to the public since 1859, was incorporated in Oregon in 1910, and began doing business as NW Natural in 1997. NW Natural's natural gas distribution activities are reported in the natural gas distribution (NGD) segment. All other business activities, including certain gas storage activities, water and wastewater businesses, non-regulated renewable natural gas activities and other investments and activities are aggregated and reported as "other" at their respective registrant.

NATURAL GAS DISTRIBUTION (NGD) SEGMENT

Both NW Holdings and NW Natural have one reportable segment, the NGD segment, which is operated by NW Natural. NGD provides natural gas service through approximately 795,000 meters in Oregon and southwest Washington. Approximately 88% of customers are located in Oregon and 12% are located in southwest Washington.

NW Natural has been allocated an exclusive service territory by the Oregon Public Utility Commission (OPUC) and Washington Utilities and Transportation Commission (WUTC), which includes the major population centers in western Oregon, including the Portland metropolitan area, most of the Willamette Valley, the Coastal area from Astoria to Coos Bay, and portions of Washington along the Columbia River. Major businesses located in NW Natural's service territory include retail, manufacturing, and high-technology industries.

Customers

The NGD business serves residential, commercial, and industrial customers with no individual customer accounting for more than 10% of NW Natural's or NW Holdings' revenues. On an annual basis, residential and commercial customers typically account for approximately 60% of NGD volumes delivered and approximately 90% of NGD margin. Industrial and other customers largely account for the remaining volumes and margin.

The following table presents summary meter information for the NGD segment as of December 31, 2022:

	Number of Meters	% of Volumes	% of Margin
Residential	724,287	38 %	65 %
Commercial	69,139	23 %	25 %
Industrial	1,071	39 %	7 %
Other[(1)]	N/A	N/A	3 %
Total	794,497	100 %	100 %

(1) NGD margin is also affected by other items, including miscellaneous revenues, gains or losses from NW Natural's gas cost incentive sharing mechanism, other margin adjustments, and other regulated services.

Generally, residential and commercial customers purchase both their natural gas commodity (gas sales) and natural gas delivery services (transportation services) from the NGD business. Industrial customers also purchase transportation services, but may buy the gas commodity either from NW Natural or directly from a third-party gas marketer or supplier. Gas commodity cost is primarily a pass-through cost to customers; therefore, profit margins are not significantly affected by an industrial customer's decision to purchase gas from NW Natural or from third parties. Industrial and large commercial customers may also select between firm and interruptible service levels, with firm services generally providing higher profit margins compared to interruptible services.

To help manage gas supplies, industrial tariffs are designed to provide some certainty regarding industrial customers' volumes by requiring an annual service election, special rates or possible restrictions for changes between elections, and in some cases, a minimum or maximum volume requirement before changing options.

We estimate natural gas was in approximately 63% of single-family residential homes in NW Natural's service territory in 2022. Customer growth in our region comes mainly from the following sources: single-family housing, both new construction and conversions; multifamily housing new construction; and commercial buildings, both new construction and conversions. Single-family new construction has consistently been our largest source of growth. Continued customer growth is closely tied to consumer preference for natural gas, the comparative price of natural gas to electricity and fuel oil, regulations and building codes permitting the use of natural gas in new construction and conversions, and the economic health of our service territory.

Competitive Conditions

In its service areas, the NGD business has no direct competition from other natural gas distributors. However, it competes with other forms of energy in each customer class. This competition among energy suppliers is based on price, efficiency, reliability, performance, preference, market conditions, building codes, technology, federal, state, and local energy policy, and environmental impacts.

For residential and small to mid-size commercial customers, the NGD business competes primarily with providers of electricity, fuel oil, and propane.

In the industrial and large commercial markets, the NGD business competes with all forms of energy, including competition from wholesale natural gas marketers. In addition, large industrial customers could bypass NW Natural's natural gas distribution system by installing their own direct pipeline connection to the interstate pipeline system. NW Natural has designed custom transportation service agreements with several large industrial customers to provide transportation service rates that are competitive with the customer’s costs of installing their own pipeline.

Seasonality of Business

The NGD business is seasonal in nature due to higher gas usage by residential and commercial customers during the cold winter heating months. Other categories of customers experience similar seasonality in their usage but to a lesser extent.

Regulation and Rates

The NGD business is subject to regulation by the OPUC and WUTC. These regulatory agencies authorize rates and allow recovery mechanisms to provide the opportunity to recover prudently incurred capital and operating costs from customers, while also earning a reasonable return on investment for investors. In addition, the OPUC and WUTC also regulate the system of accounts and issuance of securities by NW Natural.

NW Natural files general rate cases and rate tariff requests periodically with the OPUC and WUTC to establish approved rates, an authorized return on equity (ROE), an overall rate of return (ROR) on rate base, an authorized capital structure, and other revenue/cost deferral and recovery mechanisms.

NW Natural is also regulated by the Federal Energy Regulatory Commission (FERC). Under NW Natural's Mist interstate storage certificate with FERC, NW Natural is required to file either a petition for rate approval or a cost and revenue study every five years to change or justify maintaining the existing rates for the interstate storage service.

For further discussion on our most recent general rate cases, see Part II, Item 7, "Results of Operations—Regulatory Matters—*Regulation and Rates*."

Gas Supply

NW Natural strives to secure sufficient, reliable supplies of natural gas to meet the needs of customers at the lowest reasonable cost, while maintaining price stability, managing gas purchase costs prudently and supporting our core value of environmental stewardship. This is accomplished through a comprehensive strategy focused on the following items:

- **Reliability** - ensuring gas resource portfolios are sufficient to satisfy customer requirements under extreme cold weather conditions;
- **Diverse Supply** - providing diversity of supply sources;
- **Diverse Contracts** - maintaining a variety of contract durations, types, and counterparties;
- **Cost Management and Recovery** - employing prudent gas cost management strategies; and

- **Environmental Stewardship** - striving to reduce the carbon content and environmental impacts of the energy we deliver.

Reliability
To support system reliability, the NGD business has developed a risk-based methodology in which it uses a planning standard to serve the highest firm sales demand day in any year with 99% certainty.

The projected maximum design day firm NGD customer sales is approximately 10 million therms. Of this total, the NGD business is currently capable of meeting approximately 50% of the requirements with gas from storage located within or adjacent to its service territory, while the remaining supply requirements would come from gas purchases under firm gas purchase contracts and recall agreements.

NW Natural segments transportation capacity, which is a natural gas transportation mechanism under which a shipper can leverage its firm pipeline transportation capacity by separating it into multiple segments with alternate delivery routes. The reliability of service on these alternate routes will vary depending on the constraints of the pipeline system. For those segments with acceptable reliability, segmentation provides a shipper with increased flexibility and potential cost savings compared to traditional pipeline service. The NGD business relies on segmentation of firm pipeline transportation capacity that flows from Stanfield, Oregon to various points south of Molalla, Oregon.

We believe gas supplies would be sufficient to meet existing NGD firm customer demand in the event of maximum design day weather conditions.

The following table shows the sources of supply projected to be used to satisfy the design day sales for the 2022-23 winter heating season:

Therms in millions	Therms	Percent
Sources of NGD supply:		
Firm supply purchases	3.4	34 %
Mist underground storage (NGD only)	3.1	30 %
Company-owned LNG storage	1.9	19 %
Off-system storage contract	0.5	5 %
Pipeline segmentation capacity	0.6	6 %
Recall agreements	0.4	4 %
Peak day citygate deliveries	0.2	2 %
Total	10.1	100 %

The OPUC and WUTC have Integrated Resource Planning (IRP) processes in which utilities define different future scenarios and corresponding resource and compliance strategies in an effort to evaluate supply and demand resource and compliance requirements, consider uncertainties in the planning process and the need for flexibility to respond to changes, and establish a plan for providing reliable service while meeting carbon compliance obligations within frameworks that emphasize least cost and risk.

NW Natural generally files a full IRP biennially for Oregon and Washington with the OPUC and the WUTC, respectively, and files updates in Oregon between filings. The OPUC acknowledges NW Natural's action plan, whereas the WUTC provides notice that the IRP has met the requirements of the Washington Administrative Code. OPUC acknowledgment of the IRP does not constitute ratemaking approval of any specific resource acquisition strategy or expenditure. For additional information see Part II, Item 7, "Results of Operations—*Regulatory Matters*."

Diversity of Supply Sources
NW Natural purchases gas supplies primarily from the Alberta and British Columbia provinces of Canada and multiple receipt points in the U.S. Rocky Mountains to protect against regional supply disruptions and to take advantage of price differentials. For 2022, 60% of gas supply came from Canada, with the balance primarily coming from the U.S. Rocky Mountain region. The extraction of shale gas has increased the availability of gas supplies throughout North America. We believe gas supplies available in the western United States and Canada are adequate to serve NGD customer requirements for the foreseeable future. NW Natural continues to evaluate the long-term supply mix based on projections of gas production and pricing in the U.S. Rocky Mountain region as well as other regions in North America.

NW Natural supplements firm gas supply purchases with gas withdrawals from gas storage facilities, including underground reservoirs and LNG storage facilities. Storage facilities are generally injected with natural gas during the off-peak months in the spring and summer, and the gas is withdrawn for use during peak demand months in the winter.

The following table presents the storage facilities available for NGD business supply:

	Maximum Daily Deliverability (therms in millions)	Designed Storage Capacity (Bcf)
Gas Storage Facilities		
Owned Facility		
Mist, Oregon (Mist Facility)(1)	3.1	11.7
Mist, Oregon (North Mist Facility)(2)	1.3	4.1
Contracted Facility		
Jackson Prairie, Washington(3)	0.5	1.1
LNG Facilities		
Owned Facilities		
Newport, Oregon	0.6	1.0
Portland, Oregon	1.3	0.6
Total	6.8	18.5

(1) The Mist gas storage facility has a total maximum daily deliverability of 5.1 million therms and a total designed storage capacity of about 17.5 Bcf, of which 3.1 million therms of daily deliverability and 11.7 Bcf of storage capacity are reserved for NGD business customers.
(2) The North Mist facility is contracted to exclusively serve Portland General Electric, a local electric utility, and may not be used to serve other NGD customers. See "*North Mist Gas Storage Facility*" below for more information.
(3) The storage facility is located near Chehalis, Washington and is contracted from Northwest Pipeline, a subsidiary of The Williams Companies.

The Mist facility serves NGD segment customers and is also used for non-NGD purposes, primarily for contracts with gas storage customers, including utilities and third-party marketers. Under regulatory agreements with the OPUC and WUTC, gas storage at Mist can be developed in advance of NGD customer needs but is subject to recall when needed to serve such customers as their demand increases. When storage capacity is recalled for NGD purposes it becomes part of the NGD segment. In 2022, the NGD business did not recall additional deliverability or associated storage capacity to serve customer needs. The North Mist facility is contracted for the exclusive use of Portland General Electric, a local electric utility, and may not be used to serve other NGD customers. See "*North Mist Gas Storage Facility*" below.

Diverse Contract Durations and Types

NW Natural has a diverse portfolio of short-, medium-, and long-term firm gas supply contracts and a variety of contract types including firm and interruptible supplies as well as supplemental supplies from gas storage facilities.

The portfolio of firm gas supply contracts typically includes the following gas purchase contracts: year-round and winter-only baseload supplies; seasonal supply with an option to call on additional daily supplies during the winter heating season; and daily or monthly spot purchases.

During 2022, a total of 886 million therms were purchased under contracts with durations as follows:

Contract Duration (primary term)	Percent of Purchases
Long-term (one year or longer)	29 %
Short-term (more than one month, less than one year)	34
Spot (one month or less)	37
Total	100 %

Gas supply contracts are renewed or replaced as they expire. During 2022, there was one supplier that provided 10% of the NGD business gas supply requirements. No other individual supplier provided 10% or more of the NGD business gas supply requirements.

Gas Cost Management

The cost of gas sold to NGD customers primarily consists of the following items, which are included in annual Purchased Gas Adjustment (PGA) rates: gas purchases from suppliers; charges from pipeline companies to transport gas to our distribution system; gas storage costs; gas reserves contracts; gas commodity derivative contracts; and renewable natural gas and its attributes, including renewable thermal certificates (RTCs). We expect that costs to comply with Oregon's Climate Protection Program (CPP) and Washington's Climate Commitment Act (CCA) programs will be included in the cost of gas.

The NGD business employs a number of strategies to mitigate the cost of gas sold to customers. The primary strategies for managing gas commodity price risk include:

- negotiating fixed prices directly with gas suppliers;
- negotiating financial derivative contracts that: (1) effectively convert floating index prices in physical gas supply contracts to fixed prices (referred to as commodity price swaps); or (2) effectively set a ceiling or floor price, or both, on floating index priced physical supply contracts (referred to as commodity price options such as calls, puts, and collars);
- buying physical gas supplies at a set price and injecting the gas into storage for price stability and to minimize pipeline capacity demand costs; and
- investing in gas reserves for longer term price stability. See Note 13 for additional information about our gas reserves.

NW Natural also contracts with an independent energy marketing company to capture opportunities regarding storage and pipeline capacity when those assets are not serving the needs of NGD business customers. Asset management activities provide opportunities for cost of gas savings for customers and incremental revenues for NW Natural through regulatory incentive-sharing mechanisms. These activities, net of the amount shared, are included in other for segment reporting purposes.

<u>Gas Cost Recovery</u>
Mechanisms for gas cost recovery are designed to be fair and reasonable, with an appropriate balance between the interests of customers and NW Natural. In general, natural gas distribution rates are designed to recover the costs of, but not to earn a return on, the gas commodity sold. Risks associated with gas cost recovery are minimized by resetting customer rates annually through the PGA and aligning customer and shareholder interests through the use of sharing, weather normalization, and conservation mechanisms in Oregon. See Part II, Item 7, "Results of Operations—*Regulatory Matters*" and "Results of Operations—Business Segments—Natural Gas Distribution Operations—*Cost of Gas*".

<u>Environmental Stewardship</u>
Part of our gas supply strategy is working to reduce the carbon content and the environmental impacts of the energy we deliver. To that end, NW Natural developed and implemented an emissions screening tool that uses Environmental Protection Agency (EPA) data to calculate the relative emissions intensity of gas producer operations and prioritize purchases from lower emitting producers. In 2019, we began using this emissions intensity screening tool alongside other purchasing criteria such as price, credit worthiness and geographic diversity. The result has been a cost-neutral way to reduce carbon emissions associated with our natural gas supply.

NW Natural is focused on taking steps to lower its emissions on behalf of customers by purchasing environmental attributes that are generated by the production of renewable natural gas (RNG). Under Oregon Senate Bill 98, NW Natural can purchase or invest in RNG facilities, which generate these environmental attributes known as Renewable Thermal Certificates (RTCs). The RTCs work like renewable energy certificates, or RECs, used in electricity markets. RTCs are verified and certified by the Midwest Renewable Energy Tracking System (M-RETS). The M-RETS Renewable Thermal Tracking System issues one RTC for every dekatherm of RNG injected into the gas system. NW Natural enters into contracts for the purchase of RNG and RTCs either through periodic request for proposals or through formal offerings or informal requests. See Part II, Item 7, "Results of Operations—*Regulatory Matters*".

In addition to purchases of RNG, NW Natural is subject to the carbon-reduction requirements of the Oregon CPP and the Washington CCA programs. NW Natural has modeled pathways to compliance with the CPP and CCA in its most recent IRP, which are currently under review by the OPUC and WUTC. While costs associated with each possible compliance pathway differ, we intend to pursue recovery of the costs associated with these programs in rates.

<u>Transportation of Gas Supplies</u>
NW Natural's gas distribution system is reliant on a single, bi-directional interstate transmission pipeline to bring gas supplies into the natural gas distribution system. Although dependent on a single pipeline, the pipeline's gas flows into the Portland metropolitan market from two directions: (1) the north, which brings supplies from the British Columbia and Alberta supply basins; and (2) the east, which brings supplies from Alberta as well as the U.S. Rocky Mountain supply basins.

NW Natural incurs monthly demand charges related to firm pipeline transportation contracts. These contracts have expiration dates ranging from 2023 to 2061. The largest pipeline agreements are with Northwest Pipeline. NW Natural actively works with Northwest Pipeline and others to renew contracts in advance of expiration to ensure gas transportation capacity is sufficient to meet customer needs.

Rates for interstate pipeline transportation services are established by FERC within the U.S. and by Canadian authorities for services on Canadian pipelines.

<u>Gas Distribution</u>
Safety and the protection of employees, customers, and our communities are, and will remain, top priorities. NW Natural constructs, operates, and maintains its pipeline distribution system and storage operations with the goal of ensuring natural gas is delivered and stored safely, reliably, and efficiently.

NW Natural has one of the most modern distribution systems in the country with no identified cast iron pipe or bare steel main. Since the 1980s, NW Natural has taken a proactive approach to replacement programs and partnered with the OPUC and WUTC on progressive regulation to further safety and reliability efforts for the distribution system. In the past, NW Natural had a cost recovery program in Oregon that encompassed programs for cast iron replacement, bare steel replacement, transmission integrity management, and distribution integrity management programs as appropriate.

Natural gas distribution businesses are likely to be subject to greater federal and state regulation in the future. Additional operating and safety regulations from the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) are currently under development. In 2016, PHMSA issued a notice of proposed rulemaking titled the "Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments." In 2019, PHMSA issued the first of three portions of the rulemaking which went into effect on July 1, 2020 and includes up to a 15-year timeline for compliance. The second portion of the rule known as the gas gathering rule was issued in late 2021, and final rulemaking titled "The Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments" was issued in August 2022. A Gas Pipeline Leak Detection rule is expected to be issued in 2023. NW Natural intends to continue to work diligently with industry associations as well as federal and state regulators to support the safety of the system and compliance with new laws and regulations. We expect the costs associated with compliance with federal, state, and local laws and regulations to be recovered in rates.

North Mist Gas Storage Facility

In May 2019, NW Natural completed an expansion of its existing gas storage facility near Mist, Oregon. The North Mist facility provides long-term, no-notice underground gas storage service and is dedicated solely to Portland General Electric (PGE) under a 30-year contract with options to extend up to an additional 50 years upon mutual agreement of the parties. PGE uses the facility to fuel its gas-fired electric power generation facilities, which backs up PGE's variable load of renewable energy on the electric grid.

North Mist includes a reservoir providing 4.1 Bcf of available storage, an additional compressor station with a contractual capacity of 120,000 dekatherms of gas deliverability per day, no-notice service that can be drawn on rapidly, and a 13-mile pipeline to connect to PGE's Port Westward gas plants in Clatskanie, Oregon.

Upon placement into service in May 2019, the facility was included in rate base under an established tariff schedule with revenues recognized consistent with the schedule. Billing rates are updated annually to the forecasted depreciable asset level and forecasted operating expenses.

While there are additional expansion opportunities in the Mist storage field, any expansion would be based on market demand, cost effectiveness, available financing, receipt of future permits, and other rights.

OTHER

Certain businesses and activities of NW Holdings and NW Natural are aggregated and reported as other for segment reporting purposes.

NW Natural

The following businesses and activities are aggregated and reported as other under NW Natural, a wholly-owned subsidiary of NW Holdings:

- 5.8 Bcf of the Mist gas storage facility contracted to other utilities and third-party marketers;
- natural gas asset management activities; and
- appliance retail center operations.

Mist Gas Storage

The Mist gas storage facility began operations in 1989. It is a 17.5 Bcf facility with 11.7 Bcf used to provide gas storage for the NGD business. The remaining 5.8 Bcf of the facility is contracted with other utilities and third-party marketers with these results reported in other. In 2022, NW Natural utilized 0.5 Bcf of increased storage capacity realized through reservoir expansion during more than 15 years of delta pressure operations. This change increased the working gas capacity from 17.0 Bcf in 2021 to 17.5 Bcf in 2022.

The overall facility consists of seven depleted natural gas reservoirs, 22 injection and withdrawal wells, a compressor station, dehydration and control equipment, gathering lines, and other related facilities. The capacity at Mist serving other utilities and third-party marketers provides multi-cycle gas storage services to customers in the interstate and intrastate markets. The interstate storage services are offered under a limited jurisdiction blanket certificate issued by FERC. Under NW Natural's interstate storage certificate with FERC, NW Natural is required to file either a petition for rate approval or a cost and revenue study every five years to change or justify maintaining the existing rates for the interstate storage service. Intrastate firm storage services in Oregon are offered under an OPUC-approved rate schedule as an optional service to certain eligible customers. Gas storage revenues from the 5.8 Bcf are derived primarily from firm service customers who provide energy-related services, including natural gas distribution, electric generation, and energy marketing. The Mist facility benefits from limited competition as there are few storage facilities in the Pacific Northwest region. Therefore, NW Natural is able to acquire high-value, multi-year contracts.

Asset Management Activities

NW Natural contracts with an independent energy marketing company to provide asset management services, primarily through the use of natural gas commodity exchange agreements and natural gas pipeline capacity release transactions. The results of these activities are included in other, except for the asset management revenues allocated to NGD business customers pursuant to regulatory agreements, which are reported in the NGD segment.

NW Holdings

These include the following businesses and activities aggregated under NW Holdings:

- NW Natural Water Company, LLC (NWN Water) and its water and wastewater utility operations;
- NWN Water's equity investment in Avion Water Company, Inc.;
- NW Natural Renewables Holdings, LLC and its non-regulated renewable natural gas activities;
- a minority interest in the Kelso-Beaver Pipeline held by our wholly-owned subsidiary NNG Financial Corporation (NNG Financial); and
- holding company and corporate activities, including business development activities, as well as adjustments made in consolidation.

NW Natural Water

NWN Water currently serves an estimated 155,000 people through approximately 62,500 water and wastewater connections across five states. NWN Water continues to grow though customer additions within or near its service territories, and continues to pursue acquisitions. For recently acquired water utilities, see further discussion about the status of water general rate cases in Part II, Item 7, "Results of Operations—Regulatory Matters—*Water General Rate Cases*."

The water and wastewater utilities primarily serve residential and commercial customers. Water distribution operations are seasonal in nature with peak demand during warmer summer months, while wastewater is less seasonally affected. Entities generally operate in exclusive service territories with no direct competitors. Water distribution customer rates are regulated by state utility commissions while the wastewater businesses we own consist of some state regulated systems and some systems that are not rate regulated by utility commissions.

NW Natural Renewables

NW Natural Renewables is a newly formed non-regulated subsidiary of NW Natural Holdings established to invest in renewable energy through the production and supply of lower-carbon fuels. NW Natural Renewables' first project is with a subsidiary of EDL, a global producer of sustainable distributed energy. In September 2021, a subsidiary of NW Natural Renewables and a subsidiary of EDL executed agreements, whereby the subsidiary of NW Natural Renewables committed $50 million toward the development of two production facilities that are designed to convert landfill waste gases to RNG and connect gas production to existing regional pipeline networks. Testing and commissioning of the production facilities is expected to occur in the spring of 2023. Alongside these development agreements, a subsidiary of NW Natural Renewables and a subsidiary of EDL executed agreements designed to secure a 20-year supply of RNG produced from the facilities for NW Natural Renewables. In 2022, NW Natural Renewables executed a four-year off-take agreement with a counterparty for the near-term RNG production. NW Natural Renewables is currently in discussions with other counterparties to contract the remaining RNG production under long-term contracts.

ENVIRONMENTAL MATTERS

Properties and Facilities

NW Natural owns, or previously owned, properties and facilities that are currently being investigated that may require environmental remediation and are subject to federal, state, and local laws and regulations related to environmental matters. These laws and regulations may require expenditures over a long time frame to address certain environmental impacts. Estimates of liabilities for environmental costs are difficult to determine with precision because of the various factors that can affect their ultimate disposition. These factors include, but are not limited to, the following:

- the complexity of the site;
- changes in environmental laws and regulations at the federal, state, and local levels;
- the number of regulatory agencies or other parties involved;
- new technology that renders previous technology obsolete, or experience with existing technology that proves ineffective;
- the level of remediation required;
- variations between the estimated and actual period of time that must be dedicated to respond to an environmentally-contaminated site; and
- the application of environmental laws that impose joint and several liabilities on all potentially responsible parties.

NW Natural has received recovery of a portion of such environmental costs through insurance proceeds, seeks the remainder of such costs through customer rates, and believes recovery of these costs is probable. In both Oregon and Washington, NW Natural has mechanisms to recover expenses. Oregon recoveries are subject to an earnings test. See Part II, Item 7, "Results of Operations—Regulatory Matters—Rate Mechanisms—*Environmental Cost Deferral and Recovery*", and Note 2 and Note 17 of the Consolidated Financial Statements in Item 8 of this report for more information.

Greenhouse Gas Matters

For information concerning greenhouse gas matters, see Part II, Item 7, "Results of Operations—Environmental Regulation and Legislation Matters."

HUMAN CAPITAL

Our core values of integrity, safety, caring, service ethic, and environmental stewardship guide how we engage with customers, stakeholders, shareholders, and communities. We actively work to foster these values in our employee culture and to nurture an inclusive and equitable environment that provides opportunities, prioritizes health and safety, encourages respect and trust, and supports growth and learning. We aim to recruit and retain employees who share our core values and reflect our communities.

Employees

At December 31, 2022, our workforce consisted of the following:

NW Natural:	
Unionized employees[1]	575
Non-unionized employees	574
Total NW Natural	1,149
Other Entities:	
Water and wastewater company employees	105
Other	4
Total other entities	109
Total Employees	1,258

(1) Members of the Office and Professional Employees International Union (OPEIU) Local No. 11, AFL-CIO.

NW Natural's labor agreement with members of OPEIU covers wages, benefits, and working conditions. In November 2019, NW Natural's unionized employees ratified a collective bargaining agreement that took effect on December 1, 2019 and extends to May 31, 2024, and thereafter from year to year unless either party serves notice of its intent to negotiate modifications to the collective bargaining agreement. During calendar year 2022, NW Natural did not incur any work stoppages (strikes or lockouts), and therefore, experienced zero idle days for the year.

Certain subsidiaries may receive services from employees of other subsidiaries. When such services involve regulated entities, those entities receiving services reimburse the entity providing services pursuant to shared services agreements, as applicable.

Safety

Safety is one of our greatest responsibilities to employees. In managing the business, we strive to foster a safety culture focused on prevention, open communication, collaboration, and a strong service and safety ethic. We believe employee safety is critical to our success. A portion of executives' compensation is tied to achieving our safety metrics, and our Board of Directors regularly reviews company safety metrics. NW Natural's health and safety policies and procedures are designed to comply with all applicable regulations, but we also work to go beyond compliance by striving to incorporate industry best practices and benchmarking.

As part of our commitment to employee health and safety, we maintain regular training programs, emergency preparedness procedures, and specific training and procedures to identify hazards and handle high-risk emergency situations. Employees complete classroom instruction and hands-on, scenario-based training at our training facility in Oregon that allows employees to experience realistic situations in a controlled environment. We also host natural gas safety training events for first responders, which are designed to prepare those first responders and NW Natural field employees to deliver an integrated, seamless response in the event of an emergency that involves or affects the natural gas system. We navigated, and continue to navigate, the COVID-19 pandemic to help keep people safe. We also implemented a new learning management system that went live in early 2021 and provides more efficiency and flexibility in how we train.

Employee Benefits and Support

To attract employees and meet the needs of our workforce, NW Natural strives to offer competitive compensation and benefits packages to employees. The benefits package options vary depending on type of employee and date of hire. NW Natural continuously looks for ways to support employees' work-life balance and well-being and this is reflected in physical, mental and financial wellness programs to meet the needs of our employees and help them care for their families. Benefits available to employees during 2022 included, among others: healthcare and other insurance coverages, wellness resources, retirement and savings plans, paid time off programs, and flexible and hybrid work schedules, where possible, employee resource groups, and culture and community-focused resources and opportunities, and employee recognition programs and discounts.

Talent Attraction and Development

In order to implement our business strategy and serve our customers, we depend upon our continuing ability to attract and retain diverse, talented professionals and a technically skilled workforce, and being able to transfer the knowledge and expertise of our workforce to new and increasingly diverse employees as our largely older workforce retires. A significant portion of our workforce is currently eligible or will reach retirement eligibility within the next five years, and therefore, we are focused on efforts to attract, train, and retain appropriately qualified and skilled workers to prevent loss of institutional knowledge or skills gaps.

NW Natural seeks to provide its employees with growth and development opportunities through programs designed to build skills and relationships. These programs currently include: (i) a culturally relevant mentoring program that creates opportunities for career growth by building relationships; (ii) a tuition assistance program for qualified educational pursuits; (iii) an internal class that provides participants with a big-picture understanding of the industry and company operations, equipping them to see how they contribute to NW Natural's success and identify opportunities for career growth; (iv) internal and external continuing educational courses relevant to areas of expertise; and (v) ongoing management and leadership training programs.

We regularly monitor employee engagement and satisfaction through a variety of tools, including our annual engagement survey that is designed to enable company leaders to gather valuable feedback and guidance from employees.

Diversity, Equity and Inclusion

We have a longstanding commitment to creating a diverse and inclusive culture that reflects and supports the communities we serve, and believe a diverse, equitable, and inclusive workforce at all levels contributes to long-term success. Our efforts in recruiting, promoting, and retaining diverse talent, building inclusive teams, and creating a culture that embraces differences are at the core of our workforce strategy. To attract diverse candidates, we work with community partners to help promote awareness of job opportunities within diverse communities.

We have employee-led groups that develop programs and activities that build awareness around issues important to their co-workers, families, customers, and our community. Groups include the Diversity, Equity & Inclusion Council, Women's Network, African American, Rainbow Alliance (LGBTQ+), Veterans, Somos Unidos (Latinx), Asian American, and Neurodiversity employee resource groups, Wellness Advisory Committee, and Sustainability and Equity Engagement Team. We also continue to emphasize diversity, equity and inclusion values through employee training and education, including expanded diversity training as part of new hire onboarding and other diversity, equity, and inclusion education that occurs throughout the year. An area of focus going forward is to understand and increase awareness of internal systems and structures that could limit representation and equity for underrepresented employees. To that end, we are working toward revising and refocusing new manager and new hire training to include implicit bias, diversity, equity and inclusion, and anti-racism education.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

For information concerning executive officers, see Part III, Item 10.

AVAILABLE INFORMATION

NW Holdings and NW Natural file annual, quarterly and current reports and other information with the Securities and Exchange Commission (SEC). The SEC maintains an Internet site where reports, proxy statements, and other information filed can be read, copied, and requested online at its website (www.sec.gov). In addition, we make available, free of charge, on our website (www.nwnaturalholdings.com), our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) and proxy materials filed under Section 14 of the Securities Exchange Act of 1934, as amended (Exchange Act), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. We intend to use our website as a means of disclosing material non-public information and for complying with our disclosure obligations under Regulation FD. Accordingly, investors should monitor our website, in addition to following our press releases, SEC filings and public conference calls and webcasts. We have included our website address as an inactive textual reference only. Information contained on our website is not incorporated by reference into this annual report on Form 10-K.

NW Holdings and NW Natural have adopted a Code of Ethics for all employees, officers, and directors that is available on our website. We intend to disclose revisions and amendments to, and any waivers from, the Code of Ethics for officers and directors on our website. Our Corporate Governance Standards, Director Independence Standards, charters of each of the committees of the Board of Directors, and additional information about NW Holdings and NW Natural are also available at the website. Copies of these documents may be requested, at no cost, by writing or calling Shareholder Services, Northwest Natural Holding Company, 250 S.W. Taylor Street, Portland, Oregon 97204, telephone 503-220-2402.

ITEM 1A. RISK FACTORS

NW Holdings' and NW Natural's business and financial results are subject to a number of risks and uncertainties, many of which are not within our control, which could adversely affect our business, financial condition, and results of operations. Additional risks and uncertainties that are not currently known to us or that are not currently believed by us to be material may also harm our businesses, financial condition, and results of operations. When considering any investment in NW Holdings' or NW Natural's securities, investors should carefully consider the following information, as well as information contained in the caption "Forward-Looking Statements", Item 7A, and our other documents filed with the SEC. This list is not exhaustive and the order of presentation does not reflect management's determination of priority or likelihood. Additionally, our listing of risk factors that primarily affects one of our businesses does not mean that such risk factor is inapplicable to our other businesses.

Legal, Regulatory and Legislative Risks

REGULATORY RISK. *Regulation of NW Holdings' and NW Natural's regulated businesses, including changes in the regulatory environment, failure of regulatory authorities to approve rates which provide for timely recovery of costs and an adequate return on invested capital, or an unfavorable outcome in regulatory proceedings may adversely impact NW Holdings' and NW Natural's financial condition and results of operations.*

The OPUC and WUTC have general regulatory authority over NW Natural's gas business in Oregon and Washington. NW Holdings' regulated water utility businesses are generally regulated by the public utility commission in the state in which a water business is located. These public utility commissions have broad regulatory authority, including: the rates charged to customers; authorized rates of return on rate base, including ROE; the amounts and types of securities that may be issued by our regulated utility companies, like NW Natural; services our regulated utility companies provide and the manner in which they provide them; the nature of investments our utility companies make; deferral and recovery of various expenses, including, but not limited to, pipeline replacement, environmental remediation costs, capital and information technology investments, commodity hedging expense, and certain employee benefit expenses such as pension costs; transactions with affiliated interests; regulatory adjustment mechanisms such as weather adjustment mechanisms, and other matters. The OPUC also regulates actions investors may take with respect to our utility companies, NW Natural and NW Holdings. Similarly, FERC has regulatory authority over NW Natural's interstate storage services. Expansion of our businesses generally results in regulation by other regulatory authorities. For example, certain of NW Holdings water companies are regulated in Idaho, Texas and Arizona.

The costs that are deemed recoverable in rates and prices regulators allow us to charge for regulated utility service, and the maximum FERC-approved rates FERC authorizes us to charge for interstate storage and related transportation services, are the most significant factors affecting both NW Natural's and NW Holdings' financial position, results of operations and liquidity. State utility regulators have the authority to disallow recovery of costs they find imprudently incurred or otherwise disallowed, and rates that regulators allow may be insufficient for recovery of costs we incur. We expect to continue to make expenditures to expand, improve and safely operate our gas and water utility distribution and gas storage systems, and to work toward decarbonizing our gas systems. Regulators can deny recovery of those costs. Furthermore, while each applicable state regulator has established an authorized rate of return for our regulated utility businesses, we may not be able to achieve the earnings level authorized. Moreover, in the normal course of business we may place assets in service or incur higher than expected levels of operating expense before rate cases can be filed to recover those costs (this is commonly referred to as regulatory lag). The failure of any regulatory commission to approve requested rate increases on a timely basis to recover costs or to allow an adequate return could adversely impact NW Holdings' or NW Natural's financial condition, results of operations and liquidity.

As companies with regulated utility businesses, we frequently have dockets open with our regulators. The regulatory proceedings for these dockets typically involve multiple parties, including governmental agencies, consumer, environmental, and other advocacy groups, and other third parties. Each party advocates for the interests that they represent, which may include lower rates, additional regulatory oversight over the company, limitations on growth or phasing out of the gas system, decisions that favor electrification, or advancing other interests. We cannot predict the timing or outcome of these proceedings, or the effects of those outcomes on NW Holdings' and NW Natural's results of operations and financial condition.

REGULATION, COMPLIANCE AND TAXING AUTHORITY RISK. *NW Holdings and NW Natural are subject to governmental regulation, and compliance with local, state and federal requirements, including taxing requirements, and unforeseen changes in or interpretations of such requirements could affect NW Holdings' or NW Natural's financial condition and results of operations.*

NW Holdings and NW Natural are subject to regulation by federal, state and local governmental authorities. We are required to comply with a variety of laws and regulations and to obtain authorizations, permits, approvals and certificates from governmental agencies in various aspects of our business. Significant changes in federal, state, or local governmental leadership can accelerate or amplify changes in existing laws or regulations, or the manner in which they are interpreted or enforced. For instance, the 2020 United States Presidential election resulted in leadership changes in many federal administrative agencies and resulted in a wide range of new policies, executive orders, rules, initiatives and other changes to fiscal, tax, regulation, environmental, climate and other federal policies, many of which have components that affect the energy sector. Similarly, although party leadership in Oregon and Washington did not significantly change in the most recent election, we could continue to face significant legislative, regulatory and other policy changes in the jurisdictions in which we operate. In addition, foreign governments may implement changes to their policies, in response to changes to U.S. policy or otherwise. Although we cannot predict the impact, if any, of these changes to our businesses, they could adversely affect NW Holdings' or NW Natural's financial condition and results of operations. Until we know what policy changes are made and how those changes impact our businesses and the business of our competitors over the long term, we will not know if, overall, we will benefit from them or will be negatively affected by them.

We cannot predict changes in laws, regulations, interpretations or enforcement or the impact of such changes. Additionally, any failure to comply with existing or new laws and regulations could result in fines, penalties or injunctive measures. For example, under the Energy Policy Act of 2005, the FERC has civil authority under the Natural Gas Act to impose penalties for current violations of nearly $1.5 million per day for each violation. In addition, as the regulatory environment for our businesses increases in complexity, the risk of inadvertent noncompliance may also increase. Changes in regulations, the imposition of additional regulations, and the failure to comply with laws and regulations could negatively influence NW Holdings' or NW Natural's operating environment and results of operations.

Additionally, changes in federal, state, local or foreign tax laws and their related regulations, or differing interpretations or enforcement of applicable law by a federal, state, local or foreign taxing authority, could result in substantial cost to us and negatively affect our results of operations. Tax law and its related regulations and case law are inherently complex and dynamic. Disputes over interpretations of tax laws may be settled with the taxing authority in examination, through programs like the Compliance Assurance Process (CAP), upon appeal or through litigation. Our judgments may include reserves for potential adverse outcomes regarding tax positions that have been or plan to be taken that may be subject to challenge by taxing authorities. Changes in laws, regulations or adverse judgments and the inherent difficulty in quantifying potential tax effects of business decisions may negatively affect NW Holdings' or NW Natural's financial condition and results of operations.

Furthermore, certain tax assets and liabilities, such as deferred tax assets and regulatory tax assets and liabilities, are recognized or recorded by NW Holdings or NW Natural based on certain assumptions and determinations made based on available evidence, such as projected future taxable income, tax-planning strategies, and results of recent operations. If these assumptions and determinations prove to be incorrect, the recorded results may not be realized, which may negatively impact the financial results of NW Holdings and NW Natural.

There is uncertainty as to how our regulators will reflect the impact of the legislation and other government regulation in rates. The resulting ratemaking treatment may negatively affect NW Holdings' or NW Natural's financial condition and results of operations.

REPUTATIONAL RISKS. *Customers', legislators', regulators' and other third parties' opinions of NW Holdings and NW Natural are affected by many factors, including system and fuel reliability and safety, protection of customer information, rates, actual or perceived effects of our products, media coverage, and public sentiment. To the extent that customers, legislators, or regulators have or develop a negative opinion of our businesses, NW Holdings' and NW Natural's financial position, results of operations and cash flows could be adversely affected.*

A number of factors can affect customers', legislators', regulators', and other third parties' perception of us or our business including: service interruptions or safety concerns due to failures of equipment or facilities or from other causes, and our ability to promptly respond to such failures; our ability to safeguard sensitive customer information; the timing and magnitude of rate increases; and volatility of rates. Customers', legislators', and regulators' opinions of us can also be affected by media coverage, including the proliferation of social media, which may include information, whether factual or not, that could damage the perception of natural gas, our brand, or our reputation.

Although we believe that natural gas serves an important role in helping our region reduce GHG emissions and move to a resilient lower-carbon energy system, certain advocacy groups have opposed the use of natural gas as a fuel source altogether and have pursued policies that limit, restrict, or impose additional costs on, the use of natural gas in a variety of contexts. Concerns raised about the use of natural gas include the potential for natural gas explosions or delivery disruptions, methane leakage along production, transportation and delivery systems, and end-use equipment, and contribution of natural gas energy use to GHG emission levels and global warming. Similarly, concerns have also been raised regarding the use of RNG or hydrogen in place of natural gas. In addition, studies and claims by advocacy groups contend that there are detrimental indoor public health effects associated with the use of natural gas, which may also impact public perception. Shifts in public sentiment due to these concerns or others that may be raised may impact further legislative initiatives, regulatory actions, and litigation, as well as behaviors and perceptions of customers, investors, lawmakers, and regulators.

If customers, legislators, regulators, or other third parties have or develop a negative opinion of us and our services, or of natural gas as an energy source generally, this could make it more difficult for us to achieve policy, legislative or regulatory outcomes supportive of our business. Negative opinions could also result in reduced customer growth, sales volumes reductions, increased use of other sources of energy, or difficulties in accessing capital markets. Any of these consequences could adversely affect NW Holdings' or NW Natural's financial position, results of operations and cash flows.

REGULATORY ACCOUNTING RISK. *In the future, NW Holdings or NW Natural may no longer meet the criteria for continued application of regulatory accounting practices for all or a portion of our regulated operations.*

If we can no longer apply regulatory accounting, we could be required to write off our regulatory assets and precluded from the future deferral of costs not recovered through rates at the time such amounts are incurred, even if we are expected to recover these amounts from customers in the future.

COVID-19 Risk

PUBLIC HEALTH RISK. *The continuation of the novel coronavirus (COVID-19) and the resulting economic conditions, or the emergence of other epidemic or pandemic crises, could materially and adversely affect NW Holdings' and NW Natural's business, results of operations, or financial condition.*

The novel coronavirus (COVID-19), which was declared a pandemic by the World Health Organization in March 2020, has resulted in widespread and severe global, national and local economic and societal disruptions. As recovery from the COVID-19 pandemic continues, resurgences or mutations of the virus, could ultimately adversely affect our business by, among other things:

- impacting the health, safety, productivity and availability of our employees and contractors;
- disrupting our access to capital markets or increasing costs of capital affecting our liquidity in the future;
- reducing demand for natural gas, particularly from commercial and industrial customers that are suffering slow-downs or ultimately close completely due to pandemic effects;
- reducing customer growth and new meter additions due to less economic, construction or conversion activity;
- limiting our ability to collect on overdue accounts or disconnect gas service for nonpayment, beyond an amount or period of time acceptable to us;
- increasing our operating costs for emergency supplies, personal protective equipment, cleaning services and supplies, remote technology and other specific needs;
- impacting our capital expenditures if construction activities are suspended or delayed;
- sickening or causing a mandatory quarantine of a large percentage of our workforce, or key workgroups with specialized skill sets, impairing our ability to perform key business functions or execute our business continuity plans;
- impacting our or our contractors' or suppliers' ability to recruit and retain qualified personnel or otherwise impairing the functioning of our supply chain or ability to rely on third parties or business partners;
- adversely affecting the asset values of NW Natural's defined benefit pension plan or causing a failure to maintain sustained growth in pension investments over time, increasing our contribution requirements;
- limiting, delaying or curtailing entirely, public utility commissions' ability to approve or authorize applications or other requests we may make with respect to our regulated businesses;
- increasing volatility in the price of natural gas; and
- creating additional cybersecurity vulnerabilities due to ongoing heavy reliance on remote working.

Additionally, the long-term effects of COVID-19 or other pandemics could create prolonged unfavorable economic conditions, slowed economic growth, inflation, which may continue to rise, or an economic recession that may result in or be accompanied by unprecedented unemployment rates and declines in the value of certain assets, adversely affecting the income and financial resources of many domestic households and businesses. It is unclear whether governmental responses to these conditions will lessen the severity or duration of any economic effects. Our operational and financial results would likely be affected by such economic conditions. Less new housing construction, fewer conversions to natural gas, higher levels of residential foreclosures and vacancies, and personal and business bankruptcies or reduced spending could all negatively affect our financial condition and results of operations.

The ultimate long-term impact of COVID-19 on our business cannot be predicted and will depend on factors beyond our knowledge or control, including resurgences of the pandemic and residual economic effects, actions taken to mitigate its effects, and the extent to which normal economic and operating conditions can continue. Any of these factors could have an adverse effect on our business, outlook, financial condition, and results of operations and cash flows, which could be significant.

Growth and Strategic Risks

STRATEGIC TRANSACTION RISK. *NW Holdings' and NW Natural's ability to successfully complete strategic transactions, including mergers, acquisitions, combinations, divestitures, joint ventures, business development projects or other strategic transactions is subject to significant risks, including the risk that required regulatory or governmental approvals may not be obtained, risks relating to unknown problems or liabilities or problems or liabilities undisclosed to us, and the risk that for these or other reasons, we may be unable to achieve some or all of the benefits that we anticipate from such transactions, which could adversely affect NW Holdings' or NW Natural's financial condition, results of operations, and cash flows.*

From time to time, NW Holdings and NW Natural have pursued and may continue to pursue strategic transactions including mergers, acquisitions, combinations, divestitures, joint ventures, business development projects or other strategic transactions, including, but not limited to, investments in RNG projects on a regulated basis by NW Natural and on a non-regulated basis by NW Holdings, as well as acquisitions by NW Holdings in the water and wastewater sectors. Any such transactions involve substantial risks, including the following:

- such transactions that are contracted for may fail to close for a variety of reasons;

- the result of such transactions may not produce revenues, earnings or cash flow at anticipated levels, which could, among other things, result in the impairment of any investments or goodwill associated with such transactions;
- acquired businesses or assets could have environmental, permitting, or other problems for which contractual protections prove inadequate;
- there may be difficulties in integration or operation costs of new businesses;
- there may exist liabilities that were not disclosed to us, that exceed our estimates, or for which our rights to indemnification from the seller are limited;
- we may be unable to obtain the necessary regulatory or governmental approvals to close a transaction or receive approvals granted subject to terms that are unacceptable to us;
- we may be unable to achieve the anticipated regulatory treatment of any such transaction as part of the transaction approval or subsequent to closing the transaction; or
- we may be unable to avoid a disposition of assets for a price that is less than the book value of those assets.

One or more of these risks could affect NW Holdings' and NW Natural's financial condition, results of operations, and cash flows.

BUSINESS DEVELOPMENT RISK. *NW Holdings' and NW Natural's business development projects may not be successful or may encounter unanticipated obstacles, costs, changes or delays that could result in a project being unsuccessful or becoming impaired, which could negatively impact NW Holdings' or NW Natural's financial condition, results of operations and cash flows.*

Business development projects involve many risks. We are currently engaged in several business development projects, including, but not limited to, several water, wastewater and RNG projects. We may also engage in other business development projects such as investments in additional long-term gas reserves, non-regulated investments in RNG projects, and purchasing, marketing and reselling of RNG and its associated attributes, CNG refueling stations, power to gas or hydrogen projects or other similar projects. Our business development activities are subject to uncertainties and changed circumstances and may not reach the scale expected, be successful or perform as anticipated. Additionally, we may not be able to obtain required governmental permits and approvals to complete our projects in a cost-efficient or timely manner, potentially resulting in delays or abandonment of the projects. We could also experience issues such as: technological challenges; ineffective scalability;failure to achieve expected outcomes; unsuccessful business models; startup and construction delays; construction cost overruns; disputes with contractors; the inability to negotiate acceptable agreements such as rights-of-way, easements, construction, gas supply or other material contracts; changes in customer demand, perception or commitment; public opposition to projects; marketing risk and changes in market regulation, behavior or prices, market volatility or unavailability,including markets for RNG and its associated attributes or other environmental attributes; the inability to receive expected tax or regulatory treatment; and operating cost increases. Additionally, we may be unable to finance our business development projects at acceptable costs or within a scheduled time frame necessary for completing the project. Any of the foregoing risks, if realized, could result in business development efforts failing to produce expected financial results and the project investment becoming impaired, and such failure or impairment could have an adverse effect on NW Holdings' or NW Natural's financial condition and results of operations.

JOINT PARTNER RISK. *Investing in business development projects through partnerships, joint ventures or other business arrangements affects our ability to manage certain risks and could adversely impact NW Holdings' or NW Natural's financial condition, results of operations and cash flows.*

We use joint ventures and other business arrangements to manage and diversify the risks of certain development projects, including NW Natural's gas reserves agreements and certain RNG projects. NW Holdings or NW Natural currently has and may further acquire or develop part-ownership interests in other projects in the future, including but not limited to, natural gas, water, wastewater, RNG, or hydrogen projects. Under these arrangements, we may not be able to fully direct the management and policies of the business relationships, and other participants in those relationships may act contrary to our interests, including making operational decisions that could negatively affect our costs and liabilities. In addition, other participants may withdraw from the project, divest important assets, become financially distressed or bankrupt, or have economic or other business interests or goals that are inconsistent with ours. We have in the past and may in the future become involved in disputes with our business partners, which could result in additional cost or divert management's attention.

NW Natural's gas reserves arrangements, which operate as a hedge backed by physical gas supplies, involve a number of risks, including: gas production that is significantly less than the expected volumes, or no gas volumes; operating costs that are higher than expected; inherent risks of gas production, including disruption to operations or a complete shut-in of the field; and one or more participants in one of these gas reserves arrangements becoming financially insolvent or acting contrary to NW Natural's interests. For example, while Jonah Energy, the counterparty in NW Natural's gas reserves arrangement, has recently issued asset-backed notes that are rated by credit agencies, Jonah Energy has previously experienced several credit rating downgrades and did not maintain any credit ratings for much of 2022. Although NW Natural intends to continue monitoring Jonah Energy's financial condition and take appropriate actions to preserve NW Natural's interests, it does not control Jonah Energy's financial condition or continued performance under the gas reserves arrangement. The cost of the original gas reserves venture is currently included in customer rates and additional wells under that arrangement are recovered at specific costs, the occurrence of one or more of these risks could affect NW Natural's ability to recover this hedge in rates. Further, new gas reserves arrangements have not been approved for inclusion in rates, and regulators may ultimately determine to not include all or a portion of future transactions in rates. The realization of any of these situations could adversely impact NW Holdings' or NW Natural's financial condition, results of operations and cash flows.

CUSTOMER GROWTH RISK. *NW Holdings' and NW Natural's NGD margin, earnings and cash flow may be negatively affected if we are unable to sustain customer growth rates in our NGD segment.*

NW Natural's NGD margins and earnings growth have largely depended upon the sustained growth of its residential and commercial customer base due, in part, to the new construction housing market, conversions of customers to natural gas from other energy sources and growing commercial use of natural gas. Building codes recently enacted and others under consideration in our territory may have the effect of reducing our natural gas customer growth rate. For example, effective February 1, 2021, building codes in Washington state require new residential homes to achieve higher levels of energy efficiency based on specified carbon emissions assumptions, which calculate electric appliances to have lower on-site GHG emissions than comparable gas appliances. This increases the cost of new home construction incorporating natural gas depending on a number of factors including home size, equipment configurations, and building envelope measures. Additionally, the Washington State Building Code Council (SBCC) voted in April 2022 to include updates in the state commercial building energy code that are expected to restrict or eliminate the use of gas space and water heating in new commercial construction. In early November, the SBCC voted to include updates to the state residential building energy code that restrict the use of gas space and water heating in residential construction, with certain exceptions including for natural gas-fired heat pumps and hybrid fuel systems.The SBBC commercial and residential rules are expected to become effective July 1, 2023. Certain jurisdictions in Oregon and the State of Oregon are considering similar measures. While we expect these types of codes to be subject to legal challenge, we cannot predict the outcome of any such challenge. Insufficient customer growth, for economic, political, public perception, policy, or other reasons could adversely affect NW Holdings' or NW Natural's utility margin, earnings and cash flows.

RISK OF COMPETITION. *Our NGD business is subject to increased competition which could negatively affect NW Holdings' or NW Natural's results of operations.*

In the residential and commercial markets, NW Natural's NGD business competes primarily with suppliers of electricity, fuel oil, and propane. In the industrial market, NW Natural competes with suppliers of all forms of energy. Competition among these forms of energy is based on price, efficiency, reliability, performance, market conditions, technology, federal, state and local governmental regulation, actual and perceived environmental impacts, and public perception. Technological improvements such as electric heat pumps, batteries or other alternative technologies, or building code restrictions affecting the ability to use certain gas appliances, could erode NW Natural's competitive advantage. If natural gas prices are high relative to other energy sources, or if the cost, environmental impact or public perception of such other energy sources improves relative to natural gas, it may negatively affect NW Natural's ability to secure new customers or retain our existing residential, commercial and industrial customers, which could have a negative impact on our customer growth rate and NW Holdings' and NW Natural's results of operations.

Our natural gas storage operations compete primarily with other storage facilities and pipelines. Increased competition in the natural gas storage business could reduce the demand for our natural gas storage services, drive prices down for our storage business, and adversely affect our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows, which could adversely affect NW Holdings' and NW Natural's financial condition, results of operations and cash flows.

Operational Risks

OPERATING RISK. *Transporting and storing natural gas and distributing natural gas and water involves numerous risks that may result in accidents and other operating risks and costs, some or all of which may not be fully covered by insurance, and which could adversely affect NW Holdings' or NW Natural's financial condition, results of operations and cash flows.*

NW Holdings and NW Natural are subject to all of the risks and hazards inherent in the businesses of gas and RNG transmission, distribution and storage, water distribution, and wastewater services including:
- earthquakes, wildfires, floods, storms, landslides and other severe weather incidents and natural hazards;
- leaks or losses of natural gas or RNG, water or wastewater, or contamination of natural gas, RNG or water by chemicals or compounds, as a result of the malfunction of equipment or facilities or otherwise;
- damages from third parties;
- operator errors;
- negative performance by our storage reservoirs, facilities, or wells that could cause us to fail to meet expected or forecasted operational levels or contractual commitments to our customers or other third parties;
- problems maintaining, or the malfunction of, pipelines, biodigester facilities, wellbores and related equipment and facilities that form a part of the infrastructure that is critical to the operation of our gas and water distribution, wastewater services, RNG and gas storage facilities;
- presence of chemicals or other compounds in RNG or natural gas that could adversely affect the performance of the system or end-use equipment;
- collapse of underground storage reservoirs;
- inadequate supplies of RNG, natural gas or water or contamination of water supplies;
- operating costs that are substantially higher than expected;

- supply chain disruptions, including unexpected price increases, or supply restrictions beyond the control of our suppliers;
- migration of gas through faults in the rock or to some area of the reservoir where existing wells cannot drain the gas effectively, resulting in loss of the gas;
- blowouts (uncontrolled escapes of gas from a pipeline or well) or other accidents, fires and explosions; and
- risks and hazards inherent in the drilling operations associated with the development of gas storage facilities, and wells.

For example, TC Pipelines, LP (TC Pipelines) has identified the presence of a chemical substance, dithiazine, at several facilities on the system of its subsidiary, Gas Transmission Northwest (GTN), and those of some upstream and downstream connecting pipeline facilities. A portion of NW Natural's gas supplies from Canada are transported on GTN's pipelines. TC Pipelines reports that dithiazine can drop out of gas streams in a powdery form at some points of pressure reduction (for example, at a regulator), and that in incidents where a sufficient quantity of the material accumulates in certain places, improper functioning of equipment can occur, which can result in increased preventative and corrective action costs. While NW Natural has not detected significant quantities of dithiazine on its system to date, we continue to monitor and could discover increased levels of dithiazine or other compounds on NW Natural's system that could affect the performance of the system or end-use equipment.

These and other operational risks could result in disruption of service, personal injury or loss of human life, damage to and destruction of property and equipment, pollution or other environmental damage, breaches of our contractual commitments, and may result in curtailment or suspension of operations, which in turn could lead to significant costs and lost revenues. Further, because our pipeline, storage and distribution facilities are in or near populated areas, including residential areas, commercial business centers, and industrial sites, any loss of human life or adverse financial outcomes resulting from such events could be significant. We could be subject to lawsuits, claims, and criminal and civil enforcement actions. Additionally, we may not be able to maintain the level or types of insurance we desire, and the insurance coverage we do obtain may contain large deductibles or fail to cover certain hazards or cover all potential losses. The occurrence of any operating risks not covered by insurance could adversely affect NW Holdings' or NW Natural's financial condition, results of operations and cash flows.

SAFETY REGULATION RISK. *NW Holdings and NW Natural may experience increased federal, state and local regulation of the safety of our systems and operations, which could adversely affect NW Holdings' or NW Natural's operating costs and financial results.*

The safety and protection of the public, our customers and our employees is and will remain our top priority. We are committed to consistently monitoring, maintaining, and upgrading our distribution systems and storage operations to ensure that RNG, natural gas and water is acquired, stored and delivered safely, reliably and efficiently. Natural gas operators are subject to robust, ongoing federal, state and local regulatory oversight, which intensifies in response to incidents. For example, the 2020 Protecting our Infrastructure of Pipelines and Enhancing Safety Act (PIPES Act) prompted PHSMA to issue three new rulemakings impacting transmission lines, gathering lines, and valve automation in response to past incidents in other parts of the country. Proposed rulemakings planned for 2023 by the Pipeline and Hazardous Materials Safety Administration (PHMSA), include regulations related to the detection and repair of leaks and safety of gas distribution pipelines.

In addition, our workplaces are subject to the requirements of the Department of Transportation, through the Federal Motor Carrier Safety Administration, and the Occupational Safety and Health Administration, as well as state and local statutes and regulations that regulate the protection of the health and safety of workers. The failure to comply with these requirements or general industry standards, including keeping adequate records or preventing occupational injuries or exposure, could expose us to civil or criminal liability, enforcement actions, and regulatory fines and penalties that may not be recoverable through our rates and could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We intend to work diligently with industry associations and federal and state regulators to comply with these regulations and other new laws. We expect there to be increased costs associated with compliance, and those costs could be significant. If these costs are not recoverable in our customer rates, they could have a negative impact on NW Holdings' and NW Natural's operating costs and financial results.

RELIANCE ON THIRD PARTIES TO SUPPLY NATURAL GAS, RNG AND ENVIRONMENTAL ATTRIBUTES OR CREDITS RISK. *NW Natural relies on third parties to supply the natural gas, RNG and environmental attributes or credits in its NGD segment, and limitations on NW Natural's ability to obtain supplies, or failure to receive expected supplies, could have an adverse impact on NW Holdings' or NW Natural's financial results.*

NW Natural's ability to secure natural gas, RNG and environmental attributes or credits depends upon its ability to purchase and receive delivery of them from third parties. NW Natural, and in some cases its suppliers, does not have control over the availability of natural gas, RNG or environmental attributes or credits, competition for those supplies, disruptions in those supplies, priority allocations on transmission pipelines, markets for those supplies, or pricing and other terms related to such supplies. Additionally, third parties on whom NW Natural relies may fail to deliver supplies for which it has contracted. For example, in October, 2018, a 36-inch pipeline near Prince George, British Columbia owned by Enbridge ruptured, disrupting natural gas flows from Canada into Washington while the ruptured pipeline and an adjacent pipeline were assessed and the ruptured pipeline was repaired. Once repaired, pressurization levels for those pipelines were reduced for a significant period of time for assessment and testing. If NW Natural is unable or limited in its ability to obtain natural gas, RNG or environmental attributes or credits from its current suppliers or new sources, it may not be able to meet customers' gas requirements or regulatory or compliance requirements, and would likely incur costs associated with actions necessary to mitigate service disruptions or regulatory compliance, which could significantly and negatively impact NW Holdings' and NW Natural's results of operations.

SINGLE TRANSPORTATION PIPELINE RISK. *NW Natural relies on a single pipeline company for the transportation of gas to its service territory, a disruption, limitation, or inadequacy of which could adversely impact its ability to meet customers' gas requirements, which could significantly and negatively impact NW Holdings' and NW Natural's results of operations.*

NW Natural's distribution system is directly connected to a single interstate pipeline, which is owned and operated by Northwest Pipeline. The pipeline's gas flows are bi-directional, transporting gas into the Portland metropolitan market from two directions: (1) the north, which brings supplies from the British Columbia and Alberta supply basins; and (2) the east, which brings supplies from the Alberta and the U.S. Rocky Mountain supply basins. If there is a rupture or inadequate capacity in, or supplies to maintain adequate pressures in, the pipeline, NW Natural may not be able to meet its customers' gas requirements and we would likely incur costs associated with actions necessary to mitigate service disruptions, both of which could significantly and negatively impact NW Holdings' and NW Natural's results of operations.

THIRD PARTY PIPELINE RISK. *NW Natural's gas storage business depends on third-party pipelines that connect our storage facilities to interstate pipelines, the failure or unavailability of which could adversely affect NW Holdings' or NW Natural's financial condition, results of operations and cash flows.*

Our gas storage facilities are reliant on the continued operation of a third-party pipeline and other facilities that provide delivery options to and from our storage facilities. Because we do not own all of these pipelines, their operations are not within our control. If the third-party pipeline to which we are connected were to become unavailable for current or future withdrawals or injections of natural gas due to repairs, damage to the infrastructure, lack of capacity or other reasons, our ability to operate efficiently and satisfy our customers' needs could be compromised, thereby potentially having an adverse impact on NW Holdings' or NW Natural's financial condition, results of operations and cash flows.

WORKFORCE RISK. *NW Holdings' and NW Natural's businesses are heavily dependent on being able to attract and retain qualified employees and maintain a competitive cost structure with market-based salaries and employee benefits, and workforce disruptions could adversely affect NW Holdings' or NW Natural's operations and results.*

NW Holdings' and NW Natural's ability to implement our business strategy and serve our customers is dependent upon our continuing ability to attract and retain diverse, talented professionals and a technically skilled workforce, and being able to transfer the knowledge and expertise of our workforce to new and increasingly diverse employees as our largely older workforce retires. A significant portion of our workforce is currently eligible or will reach retirement eligibility within the next five years, which will require that we attract, train and retain skilled workers to prevent loss of institutional knowledge or skills gaps. We face competition for qualified personnel with specific skillsets. This competition is elevated by the record low unemployment in Oregon and may result in increased pressure on wages or other challenges in recruiting or retaining personnel. Without an appropriately skilled workforce, our ability to provide quality service and meet our regulatory requirements will be challenged and this could negatively impact NW Holdings' and NW Natural's earnings. Additionally, approximately half of NW Natural workers are represented by the OPEIU Local No. 11 AFL-CIO and are covered by a collective bargaining agreement that extends to May 31, 2024. Disputes with the union representing NW Natural employees over terms and conditions of their agreement, or failure to timely and effectively renegotiate the agreement upon its expiration, could result in instability in our labor relationship or other labor disruptions that could impact the timely delivery of gas and other services from our utility and storage facilities, which could strain relationships with customers and state regulators and cause a loss of revenues. The collective bargaining agreements may also limit our flexibility in dealing with NW Natural's workforce, and the ability to change work rules and practices and implement other efficiency-related improvements to successfully compete in today's challenging marketplace, which may negatively affect NW Holdings' and NW Natural's financial condition and results of operations.

Environmental Risks

ENVIRONMENTAL LIABILITY RISK. *Certain of NW Natural's, and possibly NW Holdings', properties and facilities may pose environmental risks requiring remediation, the costs of which are difficult to estimate and which could adversely affect NW Holdings' and NW Natural's financial condition, results of operations, and cash flows.*

NW Natural owns, or previously owned, properties that require environmental remediation or other action. NW Holdings or NW Natural may now, or in the future, own other properties that require environmental remediation or other action. NW Natural and NW Holdings accrue all material loss contingencies relating to these properties. A regulatory asset at NW Natural has been recorded for estimated costs pursuant to a deferral order from the OPUC and WUTC. In addition to maintaining regulatory deferrals, NW Natural settled with most of its historical liability insurers for only a portion of the costs it has incurred to date and expects to incur in the future. To the extent amounts NW Natural recovered from insurance are inadequate and it is unable to recover these deferred costs in utility customer rates, NW Natural would be required to reduce its regulatory assets which would result in a charge to earnings in the year in which regulatory assets are reduced. In addition, in Oregon, the OPUC approved the SRRM, which limits recovery of deferred amounts to those amounts which satisfy an annual prudence review and an earnings test that requires NW Natural to contribute additional amounts toward environmental remediation costs above approximately $10 million in years in which NW Natural earns above its authorized ROE. To the extent NW Natural earns more than its authorized

ROE in a year, it would be required to cover environmental expenses greater than the $10 million with those earnings that exceed its authorized ROE. The OPUC ordered a review of the SRRM in 2018 or when we obtain greater certainty of environmental costs, whichever occurred first. We submitted information for review in 2018, and believe we could be subject to further review. Similarly, in October 2019, the WUTC authorized an ECRM, which allows for recovery of certain past deferred and future prudently incurred remediation costs allocable to Washington through application of insurance proceeds and collections from customers, subject to an annual prudence determination. These ongoing prudence reviews, or with respect to the SRRM, the earnings test, or the periodic review could reduce the amounts NW Natural is allowed to recover, and could adversely affect NW Holdings' or NW Natural's financial condition, results of operations and cash flows.
Moreover, we may have disputes with regulators and other parties as to the severity of particular environmental matters, what remediation efforts are appropriate, whether natural resources were damaged, and the portion of the costs or claims NW Natural or NW Holdings should bear. We cannot predict with certainty the amount or timing of future expenditures related to environmental investigations, remediation or other action, the portions of these costs allocable to NW Natural or NW Holdings, or disputes or litigation arising in relation thereto.

Environmental liability estimates are based on current remediation technology, industry experience gained at similar sites, an assessment of probable level of responsibility, and the financial condition of other potentially responsible parties. However, it is difficult to estimate such costs due to uncertainties surrounding the course of environmental remediation, the preliminary nature of certain site investigations, natural recovery of the site, unavoidable limitations associated with environmental investigations and remedial technologies, evolving science, and the application of environmental laws that impose joint and several liabilities on all potentially responsible parties. These uncertainties and disputes arising therefrom could lead to further adversarial administrative proceedings or litigation, with associated costs and uncertain outcomes, all of which could adversely affect NW Holdings' or NW Natural's financial condition, results of operations and cash flows.

ENVIRONMENTAL REGULATION COMPLIANCE RISK. *NW Holdings and NW Natural are subject to environmental regulations for our ongoing businesses, compliance with which or failure to comply with, could adversely affect our operations or financial results.*

NW Holdings and NW Natural are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities relating to protection of the environment, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, groundwater quality and availability, plant and wildlife protection, the emitting of greenhouse gases, and other aspects of environmental regulation. For example, our natural gas operations are subject to reporting requirements to a number of governmental authorities including, but not limited to, the Environmental Protection Agency (EPA), the Oregon Department of Environmental Quality (ODEQ), and the Washington State Department of Ecology regarding greenhouse gas emissions. We are also required to reduce emissions of GHGs over time in accordance with the Oregon Climate Protection Program and the Washington Climate Commitment Act. These and other current and future additional environmental regulations at the local, state or national level could result in increased compliance costs or additional operating restrictions, which may or may not be recoverable in customer rates, through insurance or otherwise. If these costs are not recoverable, or if these regulations reduce the desirability, availability, or cost-competitiveness of natural gas, they could have an adverse effect on NW Holdings' or NW Natural's operations or financial condition. Furthermore, failure to comply with such laws or regulations could subject us to possible enforcement actions, financial liability or litigation, any of which could adversely affect NW Holdings' or NW Natural's financial condition and results of operations.

GLOBAL CLIMATE CHANGE RISK. *Our businesses may be subject to physical risks associated with climate change, all of which could adversely affect NW Holdings' or NW Natural's financial condition, results of operations and cash flows.*

Climate change may cause physical risks, including an increase in sea level, intensified storms, water scarcity, wildfire susceptibility and intensity and changes in weather conditions, such as changes in precipitation, average temperatures and extreme wind or other extreme weather events or climate conditions. Moreover, a significant portion of the nation's gas infrastructure is located in areas susceptible to storm damage that could be aggravated by wetland and barrier island erosion, which could give rise to gas supply interruptions and price spikes.

These and other physical changes could result in disruptions to natural gas production and transportation systems potentially increasing the cost of gas and affecting our natural gas businesses' ability to procure or transport gas to meet customer demand. These changes could also affect our distribution systems resulting in increased maintenance and capital costs, disruption of service, regulatory actions and lower customer satisfaction. Similar disruptions could occur in NW Holdings' water utility businesses. Additionally, to the extent that climate change adversely impacts the economic health or weather conditions of our service territory directly, it could adversely impact customer demand or our customers ability to pay. Such physical risks could have an adverse effect on NW Holdings' or NW Natural's financial condition, results of operations, and cash flows.

PUBLIC PERCEPTION AND POLICY RISK. *Changes in public sentiment or public policy with respect to natural gas, including through local, state or federal laws or legislation or other regulation (including ballot initiatives, executive orders or regulatory codes) or litigation, could adversely affect NW Holdings' or NW Natural's financial condition, results of operations and cash flows.*

There are a number of international, federal, state, and local legislative, legal, regulatory and other initiatives being proposed and adopted in an attempt to measure, control or limit the effects of global warming and climate change, including greenhouse gas (GHG) emissions such as carbon dioxide, nitrous oxide, and methane. Legislation or other forms of public policy or regulation that aim to reduce GHG emissions at the federal, state, or local level have and could continue to take a variety of forms including, but not limited to, GHG emissions limits, reporting requirements, carbon taxes, requirements to purchase carbon credits, building codes, increased efficiency standards, additional charges to fund energy efficiency activities or other regulatory actions, and incentives or mandates to conserve energy, or use renewable energy sources. Federal, state, or local governments may provide tax advantages and other subsidies to support alternative energy sources, withdraw funding from fossil fuel sources, mandate the use of specific fuels or technologies, prohibit the use of natural gas, or promote research into new technologies to reduce the cost and increase the scalability of alternative energy sources. In 2021, the United States rejoined the Paris Agreement on Climate Change, and the United States Presidential administration has issued executive orders aimed at reducing GHG emissions, has declared climate change a national security priority, and continues to consider a wide range of policies, executive orders, rules, legislation and other initiatives to address climate change. For example, the Inflation Reduction Act of 2022 (IRA), was signed into law in August 2022 and includes a number of energy and climate related provisions including funding for the EPA to improve GHG reporting and enforcement, as well as a methane fee applicable to activities associated with gas production and processing facilities, transmission pipelines and certain storage facilities. The U.S. Congress may also pass federal climate change legislation in the future. Additionally, other federal agencies have taken or are expected to take actions related to climate change. For example, in March 2022, the Securities and Exchange Commission (SEC) proposed new rules relating to the disclosure of a range of climate-related matters, PHMSA is expected to prepare regulations and other actions to limit methane emissions and the Commodities Futures Trading Commission (CFTC) has indicated it intends to take actions related to oversight of climate-related financial risks as pertinent to the derivatives and underlying commodities markets. Similarly, other federal agencies and regulations, including but not limited to the Consumer Products Safety Commission, the U.S. Department of Treasury, Federal Acquisitions Regulations, and others have indicated impending actions related to regulation related to climate change.

At the state level, the State of Washington has enacted the Climate Commitment Act (CCA), which establishes a comprehensive program that provides an overall limit for GHG emissions from major sources in the state that begins on January 1, 2023 and declines yearly to 95% below 1990 levels by 2050. Similarly, in Oregon, in March 2020, the Oregon Governor issued an executive order (EO) establishing GHG emissions reduction goals and directing state agencies and commissions (including the ODEQ and the OPUC) to facilitate such GHG emission goals. In December 2021, the ODEQ concluded its process and issued final cap and reduce rules for the Climate Protection Program (CPP), which became effective January 1, 2022. The CPP outlines GHG emissions reduction goals of 50% by 2035 and 90% by 2050 from a 1990 baseline. NW Natural is subject to both the CCA and CPP. We expect that there will be additional efforts to address climate change in the 2023 legislative sessions in both Oregon and Washington and we cannot predict whether the legislatures will pass any climate related legislation and the potential impact any such legislation may have on the Company. In addition, the State of Washington has enacted and the State of Oregon and some local jurisdictions are considering building codes that could have the effect of disfavoring or disallowing natural gas in residential or commercial new construction or conversions, including locations within our service territory, such as the recent actions by the City of Eugene to disallow gas in new residential construction beginning with permits issued in mid-2023. A number of local and county jurisdictions are also proposing or passing renewable energy resolutions or other measures in an effort to accelerate renewable energy goals.

Such current or future legislation, regulation or other initiatives (including executive orders, ballot initiatives or ordinances) could impose on our natural gas businesses operational requirements or restrictions, additional charges to fund energy efficiency initiatives, or levy a tax based on carbon content. In addition, certain jurisdictions, including San Francisco, Seattle, and New York have enacted measures to ban or discourage the use of new natural gas hookups in residential or other buildings. Other jurisdictions, including several in our service territory, such as the city of Milwaukie, have considered or are currently considering similar restrictions or other measures discouraging the use of natural gas, such as limitations or bans on the use of natural gas in new construction, requiring the conversion of buildings to electric heat, or adopting policies or incentives to encourage the use of electricity in lieu of natural gas. Such restrictions could adversely impact customer growth or usage and could adversely impact our ability to recover costs and maintain reasonable customer rates. In addition, certain cities, local jurisdictions and private parties have initiated lawsuits against companies related to climate change impacts, GHG emissions or climate-related disclosures. While NW Natural has not been subject to such litigation to date, such climate-related claims or actions could be costly to defend and could negatively impact our business, reputation, financial condition, and results of operations.

NW Natural believes natural gas has an important role in moving the Pacific Northwest to a low carbon future, and to that end is developing programs and measures to reduce carbon emissions. However, NW Natural's efforts may not happen quickly enough to keep pace with legislation or other regulation, legal changes or public sentiment, or may be more costly or not be as effective as expected. Any of these initiatives, or our unsuccessful response to them, could result in us incurring additional costs to comply with the imposed policies, regulations, restrictions or programs, provide a cost or other competitive advantage to energy sources other than natural gas, reduce demand for natural gas, restrict our customer growth, impose costs or restrictions on end users of natural gas, impact the prices we charge our customers, increase the likelihood of litigation, impose increased costs on us associated with the adoption of new infrastructure and technology to respond to such requirements which may or may not be recoverable in customer rates, and could negatively impact public perception of our services or products that negatively diminishes the value of our brand, all of which could adversely affect NW Holdings' or NW Natural's business operations, financial condition and results of operations.

Business Continuity and Technology Risks

BUSINESS CONTINUITY RISK. *NW Holdings and NW Natural may be adversely impacted by local or national disasters, political unrest, terrorist activities, cyber-attacks or data breaches, and other extreme events to which we may not be able to promptly respond, which could adversely affect NW Holdings' or NW Natural's operations or financial condition.*

Local or national disasters, political unrest, terrorist activities, cyber-attacks and data breaches, and other extreme events are a threat to our assets and operations. Companies in critical infrastructure industries may face a heightened risk due to being the target of, and having heightened exposure to, acts of terrorism or sabotage, including physical and security breaches of our physical infrastructure and information technology systems in the form of cyber-attacks or other forms of attacks. These attacks could, among other things, target or impact our technology or mechanical systems that operate our distribution, transmission or storage facilities and result in a disruption in our operations, damage to our system and inability to meet customer requirements. In addition, the threat of terrorist activities could lead to increased economic instability and volatility in the price of RNG, natural gas or other necessary commodities that could affect our operations. Threatened or actual national disasters or terrorist activities may also disrupt capital or bank markets and our ability to raise capital or obtain debt financing, or impact our suppliers or our customers directly. Local disaster or civil unrest could result in disruption of our infrastructure or part of our workforce being unable to operate or maintain our infrastructure or perform other tasks necessary to conduct our business. A slow or inadequate response to events may have an adverse impact on our operations and earnings. We may not be able to maintain sufficient insurance to cover all risks associated with local and national disasters, terrorist activities, cyber-attacks and other attacks or events. Additionally, large scale natural disasters or terrorist attacks could destabilize the insurance industry making the insurance we do have unavailable, which could increase the risk that an event could adversely affect NW Holdings' or NW Natural's operations or financial results.

RELIANCE ON TECHNOLOGY RISK. *NW Holdings' and NW Natural's efforts to integrate, consolidate and streamline each of their operations has resulted in increased reliance on technology, the failure of which could adversely affect NW Holdings' or NW Natural's financial condition and results of operations.*

NW Holdings and NW Natural have undertaken a variety of initiatives to integrate, standardize, centralize and streamline operations. These efforts have resulted in greater reliance on technological tools such as, at NW Natural: an enterprise resource planning system, a digital dispatch system, an automated meter reading system, a web-based ordering and tracking system, and other similar technological tools and initiatives. Our future success will depend, in part, on our ability to anticipate and adapt to technological changes in a cost-effective manner and to offer, on a timely basis, services that meet customer demands and evolving industry standards. New technologies may emerge that could be superior to, or may not be compatible with, some of our existing technologies, and may require us to make significant expenditures to remain competitive. We continue to implement technology to improve our business processes and customer interactions. In addition, our various existing information technology systems require periodic modifications, upgrades and/or replacement. For example, NW Natural has recently implemented upgrades to its SAP system and intends to replace its customer information system in the near future.

There are various risks associated with these systems in addition to upgrades and replacements, including hardware and software failure, communications failure, data distortion or destruction, unauthorized access to data, misuse of proprietary or confidential data, unauthorized control through electronic means, programming mistakes and other inadvertent errors or deliberate human acts. In addition, we are dependent on a continuing flow of important components and appropriately skilled individuals to maintain and upgrade our information technology systems. Our suppliers have faced disruptions due to COVID-19 and may face additional production or import delays due to natural disasters, strikes, lock-outs, political unrest, pandemics (including COVID-19) or other such circumstances. Technology services provided by third-parties also could be disrupted due to events and circumstances beyond our control which could adversely impact our business, financial condition and results of operations.

Any modifications, upgrades, system maintenance or replacements subject us to inherent costs and risks, including potential disruption of our internal control structure, substantial capital expenditures, additional administrative and operating expenses, retention of sufficiently skilled personnel to implement and operate the new systems, and other risks and costs of delays or difficulties in transitioning to new systems or of integrating new systems into our current systems. In addition, the difficulties with implementing new technology systems may cause disruptions in our business operations and have an adverse effect on our business and operations, if not anticipated and appropriately mitigated. There is also risk that we may not be able to recover all costs associated with projects to improve our technological capabilities, which may adversely affect NW Holdings' or NW Natural's financial condition and results of operations.

CYBERSECURITY RISK. *NW Holdings' and NW Natural's status as an infrastructure services provider coupled with its reliance on technology could result in a security breach which could adversely affect NW Holdings' or NW Natural's financial condition and results of operations.*

Although we take precautions to protect our technology systems and are not aware of any material security breaches to date, there is no guarantee that the procedures we have implemented to protect against unauthorized access to secured data and systems, including our industrial controls and other information technology systems, are adequate to safeguard against all security breaches or other cyberattacks. Additionally, the facilities and systems of clients, suppliers and third party service providers also could be vulnerable to cyber risks and attacks, and such third party systems may be interconnected to our systems. Therefore, an event caused by cyberattacks or other malicious act at an interconnected third party could impact our business and facilities similarly. As these potential cyber security attacks become more common and sophisticated, we could be required to incur costs to strengthen our systems or maintain insurance coverage against potential losses. Moreover, a variety of regulatory agencies are increasingly focused on cybersecurity risks, and specifically in critical infrastructure sectors. For example, the Transportation Security Administration (TSA) has published multiple security directives and is currently in the process of implementing formal rules mandating cybersecurity actions for critical pipeline owners and operators. Failure to timely and effectively meet the requirements of these directives or other cybersecurity regulations could result in fines or other penalties. We are continuing to evaluate the potential costs of implementation of these directives, and there is no assurance that we will be able to continue to recover in rates costs associated with such compliance.

In addition, our businesses could experience breaches of security pertaining to sensitive customer, employee, and vendor information maintained by us in the normal course of business, which could adversely affect our reputation, diminish customer confidence, disrupt operations, materially increase the costs we incur to protect against these risks, and subject us to possible financial liability or increased regulation or litigation. All of these risks could adversely affect NW Holdings' or NW Natural's financial condition and results of operations.

Financial and Economic Risks

HOLDING COMPANY DIVIDEND RISK. *As a holding company, NW Holdings depends on its operating subsidiaries, including NW Natural, to meet financial obligations and the ability of NW Holdings to pay dividends on its common stock is dependent on the receipt of dividends and other payments from its subsidiaries, including NW Natural.*

As a holding company, NW Holdings' only significant assets are the stock and membership interests of its operating subsidiaries, which at this time is primarily NW Natural. NW Holdings' direct and indirect subsidiaries are separate and distinct legal entities, managed by their own boards of directors, and have no obligation to pay any amounts to their respective shareholders, whether through dividends, loans or other payments. The ability of these companies to pay dividends or make other distributions on their common stock is subject to, among other things: their results of operations, net income, cash flows and financial condition, as well as the success of their business strategies and general economic and competitive conditions; the prior rights of holders of existing and future debt securities and any future preferred stock issued by those companies; and any applicable legal restrictions.

In addition, the ability of NW Holdings' subsidiaries to pay upstream dividends and make other distributions is subject to applicable state law and regulatory restrictions. Under the OPUC and WUTC regulatory approvals for the holding company formation, if NW Natural ceases to comply with credit and capital structure requirements approved by the OPUC and WUTC, it will not, with limited exceptions, be permitted to pay dividends to NW Holdings. Under the OPUC and WUTC orders authorizing the holding company reorganization, NW Natural may not pay dividends or make distributions to NW Holdings if NW Natural's credit ratings and common equity levels fall below specified ratings and levels. If NW Natural's long-term secured credit ratings are below A- for S&P and A3 for Moody's, dividends may be issued so long as NW Natural's common equity is 45% or above. If NW Natural's long-term secured credit ratings are below BBB for S&P and Baa2 for Moody's, dividends may be issued so long as NW Natural's common equity is 46% or above. Dividends may not be issued if NW Natural's long-term secured credit ratings fall to BB+ or below for S&P or Ba1 or below for Moody's, or if NW Natural's common equity is below 44%. The ratio is measured using common equity and long-term debt excluding imputed debt or debt-like lease obligations, and is determined on a preceding or projected 13-month basis.

EMPLOYEE BENEFIT RISK. *The cost of providing pension and postretirement healthcare benefits is subject to changes in pension assets and liabilities, changing employee demographics and changing actuarial assumptions, which may have an adverse effect on NW Holdings' or NW Natural's financial condition, results of operations and cash flows.*

Until NW Natural closed the pension plans to new hires, which for non-union employees was in 2006 and for union employees was in 2009, it provided pension plans and postretirement healthcare benefits to eligible full-time utility employees and retirees. Approximately 30% of NW Natural's current utility employees were hired prior to these dates, and therefore remain eligible for these plans. Other businesses we acquire may also have pension plans. The costs to NW Natural, or the other applicable businesses we may acquire, for providing such benefits is subject to change in the market value of the pension assets, changes in employee demographics including longer life expectancies, increases in healthcare costs, current and future legislative changes, and various actuarial calculations and assumptions. The actuarial assumptions used to calculate our future pension and postretirement healthcare expenses may differ materially from actual results due to significant market fluctuations and changing withdrawal rates, wage rates, interest rates and other factors. These differences may result in an adverse impact on the amount of pension contributions, pension expense or other postretirement benefit costs recorded in future periods. Sustained declines in equity markets and reductions in bond rates may have a material adverse effect on the value of the pension fund assets and liabilities. In these circumstances, NW Natural may be required to recognize increased contributions and pension expense earlier than it had planned to the extent that the value of pension assets is less than the total anticipated liability under the plans, which could have a negative impact on NW Holdings' and NW Natural's financial condition, results of operations and cash flows.

HEDGING RISK. *NW Holdings' and NW Natural's risk management policies and hedging activities cannot eliminate the risk of commodity price movements and other financial market risks, and hedging activities may expose us to additional liabilities for* *which rate recovery may be disallowed, which could result in an adverse impact on NW Holdings' and NW Natural's operating revenues, costs, derivative assets and liabilities and operating cash flows.*

NW Natural's gas purchasing requirements expose us to risks of commodity price movements, while NW Holdings' and NW Natural's use of debt and equity financing exposes us to interest rate, liquidity and other financial market risks. We attempt to manage these exposures with both financial and physical hedging mechanisms, including NW Natural's gas reserves transactions which are hedges backed by physical gas supplies and interest rate hedging arrangements at NW Holdings and NWN Water. While we have risk management procedures for hedging in place, they may not always work as planned and cannot entirely eliminate the risks associated with hedging. Additionally, our hedging activities may cause us to incur additional expenses to obtain the hedge. We do not hedge our entire interest rate or commodity cost exposure, and the unhedged exposure will vary over time. Gains or losses experienced through NW Natural's hedging activities, including carrying costs, generally flow through NW Natural's PGA mechanism or are recovered in future general rate cases. However, the hedge transactions NW Natural enters into for utility purposes are subject to a prudence review by the OPUC and WUTC, and, if found imprudent, those expenses may be, and have been previously, disallowed, which could have an adverse effect on NW Holdings' or NW Natural's financial condition and results of operations.

In addition, our actual business requirements and available resources may vary from forecasts, which are used as the basis for hedging decisions and could cause our exposure to be more or less than anticipated. Moreover, if NW Natural's derivative instruments and hedging transactions do not qualify for regulatory deferral and it does not elect hedge accounting treatment under U.S. GAAP, NW Holdings' or NW Natural's results of operations and financial condition could be adversely affected.

NW Holdings and NW Natural also have credit-related exposure to derivative counterparties. Counterparties owing NW Holdings, NW Natural or their respective subsidiaries money or physical natural gas commodities could breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements to meet our normal business requirements. In that event, NW Holdings' or NW Natural's financial results could be adversely affected. Additionally, under most of NW Natural's hedging arrangements, any downgrade of its senior unsecured long-term debt credit rating could allow its counterparties to require NW Natural to post cash, a letter of credit or other form of collateral, which would expose NW Natural to additional costs and may trigger significant increases in borrowing from its credit facilities or equity contribution needs from NW Holdings, if the credit rating downgrade is below investment grade. Further, based on current interpretations, each of NW Holdings, NW Natural and NWN Water is not considered a "swap dealer" or "major swap participant" in 2022, so we are exempt from certain requirements under the Dodd-Frank Act. If we are unable to claim this exemption, we could be subject to higher costs for our derivatives activities, and such higher costs could have a negative impact on NW Holdings' and NW Natural's operating costs and financial results.

GAS PRICE RISK. *Higher natural gas commodity prices and volatility in the price of gas may adversely affect NW Natural's NGD business, whereas lower gas price volatility may adversely affect NW Natural's gas storage business, negatively affecting NW Holdings' and NW Natural's results of operations and cash flows.*

The cost of natural gas is affected by a variety of factors, including weather, changes in demand, the level of production and availability of natural gas supplies, transportation constraints, availability and cost of pipeline capacity, federal, state and local energy and environmental policy, regulation and legislation, natural disasters and other catastrophic events, national and worldwide economic and political conditions, and the price and availability of alternative fuels. In 2021 and 2022 there was increased pricing and volatility in the current and forward gas markets. At NW Natural, the cost we pay for natural gas is generally passed through to customers through an annual PGA rate adjustment. If gas prices were to increase significantly and remain higher, it could raise the cost of energy to NW Natural's customers, potentially causing those customers to conserve or switch to alternate sources of energy. Sustained significant price increases could also cause new home builders and commercial developers to select alternative energy sources. Decreases in the volume of gas NW Natural sells could reduce NW Holdings or NW Natural's earnings, and a decline in customers could slow growth in future earnings. Additionally, notwithstanding NW Natural's current rate structure, higher gas costs could result in increased pressure on the OPUC or the WUTC to seek other means to reduce NW Natural's rates, which also could adversely affect NW Holdings' and NW Natural's results of operations and cash flows.

Temporary gas price increases can also adversely affect NW Holdings' and NW Natural's operating cash flows, liquidity and results of operations because a portion (10% or 20%) of any difference between the estimated average PGA gas cost in rates and the actual average gas cost incurred is recognized as current income or expense.

Temporary or sustained higher gas prices may also cause NW Natural to experience an increase in short-term debt and temporarily reduce liquidity because it pays suppliers for gas when it is purchased, which can be in advance of when these costs are recovered through rates. Significant increases in the price of gas can also slow collection efforts as customers experience increased difficulty in paying their higher energy bills, leading to higher than normal delinquent accounts receivable resulting in greater expense associated with collection efforts and increased bad debt expense.

INABILITY TO ACCESS CAPITAL MARKET RISK. *NW Holdings' or NW Natural's inability to access capital, or significant increases in the cost of capital, could adversely affect NW Holdings' or NW Natural's financial condition and results of operations.*

NW Holdings' and NW Natural's ability to obtain adequate and cost effective short-term and long-term financing depends on maintaining investment grade credit profiles, perceptions of our business in capital markets, and the existence of liquid and stable financial markets. NW Holdings relies on access to equity and bank markets to finance equity contributions to subsidiaries and other business requirements. NW Natural relies on access to capital and bank markets, including commercial paper and bond markets, to finance its operations, construction expenditures and other business requirements, and to refinance maturing debt that cannot be funded entirely by internal cash flows. Disruptions in capital markets, including but not limited to, pandemics, political unrest, inflationary pressures, recessionary pressures, or rising interest rates could adversely affect our ability to access short-term and long-term financing or refinance maturing indebtedness. Our access to funds under committed credit facilities, which are currently provided by a number of banks, is dependent on the ability of the participating banks to meet their funding commitments. Those banks may not be able to meet their funding commitments if they experience shortages of capital and liquidity. Disruptions in the bank or capital financing markets as a result of economic uncertainty, changing or increased regulation of the financial sector, or failure of major financial institutions, or disruptions in credit markets, could adversely affect NW Holdings' and NW Natural's access to capital and negatively impact our ability to run our businesses, achieve NW Natural's authorized rate of return, and make strategic investments.

Furthermore, recent trends toward investments that are perceived to be "green" or "sustainable" could shift capital away from, or increase the cost of capital for, our natural gas business. We believe our business is an important component of a low carbon future and are striving to decarbonize our systems. Nevertheless, perceptions in the financial markets could differ or outpace our decarbonization progress and result in a shift funding away from, or limit or restrict certain forms of funding for, natural gas businesses.

NW Natural is currently rated by S&P and Moody's and a negative change in its credit ratings, particularly below investment grade, could adversely affect its cost of borrowing and access to sources of liquidity and capital. Such a downgrade could further limit its access to borrowing under available credit lines. Additionally, downgrades in its current credit ratings below investment grade could cause additional delays in NW Natural's ability to access the capital markets while it seeks supplemental state regulatory approval, which could hamper its ability to access credit markets on a timely basis. NW Holdings' credit profile is largely supported by NW Natural's credit ratings and any negative change in NW Natural's credit ratings would likely negatively impact NW Holdings' access to sources of liquidity and capital and cost of borrowing. A credit downgrade to NW Natural, or resulting negative impact on NW Holdings, could also require additional support in the form of letters of credit, cash or other forms of collateral and otherwise adversely affect NW Holdings' or NW Natural's financial condition and results of operations.

IMPAIRMENT OF LONG-LIVED ASSETS OR GOODWILL RISK. *Impairments of the value of long-lived assets or goodwill could have a material effect on NW Holdings' or NW Natural's financial condition, or results of operations.*

NW Holdings and NW Natural review the carrying value of long-lived assets other than goodwill whenever events or changes in circumstances indicate the carrying amount of the assets might not be recoverable. The determination of recoverability is based on the undiscounted net cash flows expected to result from the operation of such assets. Projected cash flows depend on the future operating costs and projected revenues associated with the asset.

We review the carrying value of goodwill annually or whenever events or changes in circumstances indicate that such carrying value may not be recoverable. A goodwill impairment analysis begins with a qualitative analysis of events and circumstances. If the qualitative assessment indicates that the carrying value may be at risk, we will perform a quantitative assessment and recognize a goodwill impairment for any amount in which the fair value of a reporting unit exceeds its fair value. NW Holdings' total goodwill was $149.3 million as of December 31, 2022 and $70.6 million as of December 31, 2021. All of our goodwill is related to water and wastewater acquisitions. There have been no impairments recognized for the water and wastewater acquisitions to date. Any impairment charge taken with respect to our long-lived assets or goodwill could be material and could have a material effect on NW Holdings' or NW Natural's financial condition and results of operations.

CUSTOMER CONSERVATION RISK. *Customers' conservation efforts may have a negative impact on NW Holdings' and NW Natural's revenues.*

An increasing national focus on energy conservation, including improved building practices and appliance efficiencies may result in increased energy conservation by customers. This can decrease NW Natural's sales of natural gas and adversely affect NW Holdings' or NW Natural's results of operations because revenues are collected mostly through volumetric rates, based on the amount of gas sold. In Oregon, NW Natural has a conservation tariff which is designed to recover lost utility margin due to declines in residential and small commercial customers' consumption. However, NW Natural does not have a conservation tariff in Washington that provides it this margin protection on sales to customers in that state. Similar conservation risks exist for water utilities. Customers' conservation efforts may have a negative impact on NW Holdings' and NW Natural's financial condition, revenues and results of operations.

WEATHER RISK. *Warmer than average weather may have a negative impact on our revenues and results of operations.*

We are exposed to weather risk in our natural gas business, primarily at NW Natural. A majority of NW Natural's gas volume is driven by gas sales to space heating residential and small commercial customers during the winter heating season. Current NW Natural rates are based on an assumption of average weather. Warmer than average weather typically results in lower gas sales. Colder weather typically results in higher gas sales. Although the effects of warmer or colder weather on utility margin in Oregon are expected to be mitigated through the operation of NW Natural's weather normalization mechanism, weather variations from normal could adversely affect utility margin because NW Natural may be required to purchase more or less gas at spot rates, which may be higher or lower than the rates assumed in its PGA. Also, a portion of NW Natural's Oregon residential and commercial customers (usually less than 10%) have opted out of the weather normalization mechanism, and approximately 12% of its customers are located in Washington where it does not have a weather normalization mechanism. These effects could have an adverse effect on NW Holdings' and NW Natural's financial condition, results of operations and cash flows.

Water Business Risks

WATER SECTOR BUSINESS. *NW Holdings has entered the water sector through the acquisition of a number of water and wastewater companies. Water and wastewater businesses are subject to a number of risks in addition to the risks described above.*

Although the water businesses are not currently expected to materially contribute to the results of operations of NW Holdings, these businesses are subject to risks, in addition to those described above that could adversely affect their results of operations, including:

- contamination of water supplies, including water provided to customers with naturally occurring or human-made substances or other hazardous materials;
- interruptions in water supplies and service, natural disasters and droughts;
- insufficient water supplies, limitations on or disputes with respect to water rights or supplies, or the inability to secure water rights or supplies at a reasonable cost;
- disruptions to the wastewater collection and treatment process;
- reliance on third parties for water supplies and transportation of such water supplies;
- conservation efforts by customers;
- regulatory and legal requirements, including environmental, health and safety laws and regulations;
- operational risks, including customer and employee safety;
- the outcome of rate cases and other regulatory proceedings; and
- weather conditions.

Significant losses, liabilities or impairments arising from these businesses may adversely affect NW Holdings' financial position or results of operations.

INVESTMENT RISK. *NW Holdings' expectations with respect to the financial results of its investments in water operations are based on various assumptions and beliefs that may not prove accurate, resulting in failures or delays in achieving expected returns or performance.*

NW Holdings' expansion into the water sector is an important component of its growth strategy. Although NW Holdings expects its water and wastewater utility operations will result in various benefits, including expanding customer bases, providing investment opportunities through infrastructure development and enhancing regulatory relationships within the local communities served, NW Holdings may not be able to realize these or other benefits. Achieving the anticipated benefits is subject to a number of uncertainties, including whether the businesses acquired can be operated in the manner intended and whether costs to finance the acquisitions and investments will be consistent with expectations, as well as whether investments in the water sector can reach scale in a reasonable period of time. Events outside of our control, including but not limited to regulatory changes or developments, could adversely affect our ability to realize the anticipated benefits from building NW Holdings' water platform. The integration of newly acquired water businesses, particularly over a noncontiguous geographic regions, may be unpredictable, subject to delays or changed circumstances, and such businesses may not perform in accordance with our expectations. In addition, anticipated costs, level of management's attention and internal resources to achieve the integration of or operate the acquired businesses may differ significantly from our current estimates resulting in failures or delays in achieving expected returns or performance. If NW Holdings' expectations regarding the financial results of its investments in water operations prove to be inaccurate, it may adversely affect NW Holdings' financial position or results of operations.

Non-Regulated RNG Risks

INVESTMENT RISK. *NW Holdings' expectations with respect to the financial results of its investments in non-regulated RNG investments are based on various assumptions and beliefs that may not prove accurate, resulting in failures or delays in achieving expected returns.*

NW Holdings' expansion into the non-regulated RNG business is an important component of its growth strategy. Although NW Holdings expects this expansion will result in various benefits, including providing cost-effective solutions to decarbonize the utility, commercial, industrial and transportation sectors, NW Holdings may not be able to realize these or other benefits. Achieving the anticipated benefits is subject to a number of uncertainties, including whether the investments can be made at an expected scale, whether the investments can be monetized in the manner intended, and whether costs to finance the investments will be consistent with expectations. Events outside of our control, including but not limited to market or regulatory changes or developments, could adversely affect our ability to realize the anticipated benefits from building NW Holdings' non-regulated RNG platform. The establishment and growth of a non-regulated RNG business may be unpredictable, subject to uncertainties or changed circumstances, and such business may not perform in accordance with our expectations. In addition, anticipated costs, level of management's attention and internal resources to achieve the integration of the acquired investments may differ significantly from our current estimates resulting in failures or delays in achieving expected returns or performance. We could additionally experience unsuccessful business models; technological challenges; ineffective scalability or inability to achieve production volumes consistent with our expectations and marketing arrangements; construction delays or cost overruns; disputes with third party business partners; risks related to markets for RNG and its associated attributes (including changes in market regulation, behavior, or prices); the inability to receive expected tax or regulatory treatment; or unexpected operating costs. If NW Holdings' expectations regarding the financial results of its investments in non-regulated RNG prove to be inaccurate, it may adversely affect NW Holdings' financial position or results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We have no unresolved staff comments.

ITEM 2. PROPERTIES

NW Natural's Natural Gas Distribution Properties
NW Natural's natural gas pipeline system consists of approximately 14,200 miles of distribution mains, approximately 700 miles of transmission mains and approximately 10,200 miles of service lines located in its territory in Oregon and southwest Washington. In addition, the pipeline system includes service regulators and meters, as well as district regulators and metering stations. Natural gas pipelines are located in public rights-of-way pursuant to franchise agreements or other ordinances, or on lands of others pursuant to easements obtained from the owners of such lands. NW Natural also holds permits for the crossing of numerous railroads, navigable waterways and smaller tributaries throughout our entire service territory.

NW Natural owns service building facilities in Portland, Oregon, as well as various satellite service centers, garages, warehouses, and other buildings necessary and useful in the conduct of its business. Resource centers are maintained on owned or leased premises at convenient points in the distribution system to provide service within NW Natural's service territory.

NW Natural commenced a 20-year lease in March 2020 for a headquarters and operations center in Portland, Oregon.

NW Natural's Mortgage and Deed of Trust (Mortgage) is a first mortgage lien on certain gas properties owned from time to time by NW Natural, including substantially all of the property constituting NW Natural's natural gas distribution plant balances.

These properties are used in the NGD segment.

NW Natural's Natural Gas Storage Properties
NW Natural holds leases and other property interests in approximately 12,000 net acres of underground natural gas storage in Oregon and easements and other property interests related to pipelines associated with these facilities. NW Natural owns rights to depleted gas reservoirs near Mist, Oregon that are continuing to be developed and operated as underground gas storage facilities. NW Natural also holds all future storage rights in certain other areas of the Mist gas field in Oregon in addition to other leases and property interests.

NW Natural owns LNG storage facilities in Portland and near Newport, Oregon.

A portion of these properties are used in the NGD segment.

NWN Water's Distribution Properties
NWN Water owns and maintains water distribution pipes, storage, wells and other infrastructure and wastewater treatment facilities, and holds related leases and other property interests in Oregon, Washington, Idaho, Texas and Arizona. Pipelines are located in municipal streets or alleys pursuant to franchise or occupation ordinances, in county roads or state highways pursuant to agreements or permits granted pursuant to statute, or on lands of others pursuant to easements obtained from the owners of such lands. These properties are used by entities that are aggregated and reported as other under NW Holdings.

We consider all of our properties currently used in our operations, both owned and leased, to be well maintained, in good operating condition, and, along with planned additions, adequate for our present and foreseeable future needs.

ITEM 3. LEGAL PROCEEDINGS

Other than the proceedings disclosed in Note 17, we have only nonmaterial litigation in the ordinary course of business.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

NW Holdings' common stock is listed and trades on the New York Stock Exchange under the symbol NWN.

There is no established public trading market for NW Natural's common stock.

As of February 16, 2023, there were 4,249 holders of record of NW Holdings' common stock and NW Holdings was the sole holder of NW Natural's common stock.

The following table provides information about purchases of NW Holdings' equity securities that are registered pursuant to Section 12 of the Securities Exchange Act of 1934, as amended, during the quarter ended December 31, 2022:

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased[1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[2]	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[2]
Balance forward			2,124,528	$ 16,732,648
10/01/22-10/31/22	—	$ —	—	—
11/01/22-11/30/22	4,431	$ 47.34	—	—
12/01/22-12/31/22	—	$ —	—	—
Total	4,431		2,124,528	$ 16,732,648

(1) During the quarter ended December 31, 2022, no shares of NW Holdings common stock were purchased on the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan. However, 4,431 shares of NW Holdings common stock were purchased on the open market to meet the requirements of share-based compensation programs. During the quarter ended December 31, 2022, no shares of NW Holdings common stock were accepted as payment for stock option exercises pursuant to the NW Natural Restated Stock Option Plan.

(2) During the quarter ended December 31, 2022, no shares of NW Holdings common stock were repurchased pursuant to the NW Holdings Board of Directors-approved share repurchase program. In May 2019, we received NW Holdings Board of Directors approval to extend the repurchase program through May 2022. Effective August 3, 2022, we received NW Holdings Board approval to extend the repurchase program. Such authorization will continue until the program is used, terminated or replaced. For more information on this program, see Note 5.

ITEM 6. RESERVED

Not applicable.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is management's assessment of NW Holdings' and NW Natural's financial condition, including the principal factors that affect results of operations. The discussion covers the years ended December 31, 2022, 2021, and 2020 and refers to the consolidated results of NW Holdings, the substantial majority of which consist of the operating results of NW Natural. When significant activity exists at NW Holdings that does not exist at NW Natural, additional disclosure has been provided. References in this discussion to "Notes" are to the Notes to the Consolidated Financial Statements in Item 8 of this report.

NW Natural's natural gas distribution activities are reported in the natural gas distribution (NGD) segment. The NGD segment also includes NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp, the NGD-portion of NW Natural's Mist storage facility in Oregon, and NW Natural RNG Holding Company, LLC. NW Natural RNG Holding Company, LLC holds an investment in Lexington Renewable Energy, LLC, which is accounted for under the equity method. Other activities aggregated and reported as other at NW Natural include the non-NGD storage activity at Mist as well as asset management services and the appliance retail center operations. Other activities aggregated and reported as other at NW Holdings include NNG Financial's investment in Kelso-Beaver Pipeline (KB Pipeline); NW Natural Renewables Holdings, LLC and its non-regulated renewable natural gas activities; and NWN Water, which through itself or its subsidiaries, owns and continues to pursue investments in the water and wastewater sector. See Note 4 for further discussion of our business segment and other, as well as our direct and indirect wholly-owned subsidiaries.

In addition, NW Holdings has reported discontinued operations results related to the sale of Gill Ranch Storage, LLC (Gill Ranch). NW Natural Gas Storage, LLC (NWN Gas Storage), an indirect wholly-owned subsidiary of NW Holdings, entered into a Purchase and Sale Agreement during the second quarter of 2018 that provided for the sale of all membership interests in Gill Ranch. Gill Ranch owns a 75% interest in the natural gas storage facility located near Fresno, California known as the Gill Ranch Gas Storage Facility. The sale was completed on December 4, 2020. For more information, see "Results of Operations - *Discontinued Operations*" below.

NON-GAAP FINANCIAL MEASURES. In addition to presenting the results of operations and earnings amounts in total, certain financial measures are expressed in cents per share, which are non-GAAP financial measures. All references in this section to earnings per share (EPS) are on the basis of diluted shares. Such non-GAAP financial measures are used to analyze our financial performance because we believe they provide useful information to our investors and creditors in evaluating our financial condition and results of operations. Our non-GAAP financial measures should not be considered a substitute for, or superior to, measures calculated in accordance with U.S. GAAP. Moreover, these non-GAAP financial measures have limitations in that they do not reflect all the items associated with the operations of the business as determined in accordance with GAAP. Other companies may calculate similarly titled non-GAAP financial measures differently than how such measures are calculated in this report, limiting the usefulness of those measures for comparative purposes. A reconciliation of each non-GAAP financial measure to the most directly comparable GAAP financial measure is provided below.

	2022	2021	2020
Diluted EPS - Total(1)	$ 2.54	$ 2.56	$ 2.51
Diluted EPS - NGD segment(2)	2.34	2.24	2.08
Diluted EPS - NW Holdings - other(2)	0.20	0.32	0.22
Diluted EPS - Discontinued operations	—	—	0.21

(1) Total Diluted EPS is equal to the sum of Diluted EPS - NGD segment, Diluted EPS - NW Holdings – other, and Diluted EPS - Discontinued operations.
(2) Non-GAAP financial measure

EXECUTIVE SUMMARY

NW Holdings' financial results and highlights for the year include:
- Added 8,600 natural gas customers in 2022 for an annual growth rate of 1.1% at December 31, 2022;
- Invested nearly $340 million in natural gas and water utility systems to support growth, enhance reliability and resiliency, and upgrade technology;
- Scored second in the West among large utilities in the 2022 J.D. Power Gas Utility Residential Customer Satisfaction Study, making this the 19th consecutive year customers have ranked NW Natural among the top two utilities;
- Completed construction on Lexington renewable natural gas (RNG) facility procuring environmental benefits for NW Natural customers;
- Received Oregon rate case order providing a revenue requirement increase of approximately $59.4 million, with new rates effective November 1, 2022;
- Closed seven water and wastewater utility transactions in 2022, including our largest water and wastewater acquisition to date in Yuma, Arizona, bringing our total connections to approximately 62,500; and
- Increased dividends for the 67th consecutive year to shareholders.

Key financial highlights for NW Holdings include:

	2022		2021		2020	
In millions	Amount	Per Share	Amount	Per Share	Amount	Per Share
Net income from continuing operations	$ 86.3	$ 2.54	$ 78.7	$ 2.56	$ 70.3	$ 2.30
Income from discontinued operations, net of tax	—	—	—	—	6.5	0.21
Consolidated net income	$ 86.3	$ 2.54	$ 78.7	$ 2.56	$ 76.8	$ 2.51

Key financial highlights for NW Natural include:

	2022	2021	2020
In millions	Amount	Amount	Amount
Consolidated net income	$ 91.6	$ 81.2	$ 70.6
Natural gas distribution margin	$ 505.9	$ 479.8	$ 438.1

2022 COMPARED TO 2021. Consolidated net income increased $10.4 million at NW Natural primarily due to the following factors:
- $26.1 million increase in NGD segment margin driven by new rates in Oregon and Washington, customer growth, and amortization of deferred balances; and
- $12.3 million increase in other income, net primarily due to lower pension costs; partially offset by
- $16.0 million increase in operations and maintenance expenses due to higher contract labor, amortization expense related to cloud computing arrangements, information technology costs, and professional service fees;
- $3.3 million increase in interest expense primarily due to higher long-term debt balances and higher interest rates;
- $2.7 million increase in income tax expense due to an increase in pretax income;
- $2.5 million increase in depreciation expense due to additional capital investments; and
- $2.0 million increase in general taxes primarily driven by higher property taxes.

Net income from continuing operations increased $7.6 million at NW Holdings primarily due to the following factors:
- $10.4 million increase in consolidated net income at NW Natural as discussed above; partially offset by
- $2.8 million decrease in other net income primarily reflecting higher interest expense at the holding company.

Diluted EPS for NW Holdings decreased $0.02 per share primarily due to a common share issuance on April 1, 2022 and share issuances through NW Holdings' at-the-market program, partially offset by an increase in consolidated net income.

2021 COMPARED TO 2020. Consolidated net income increased $10.6 million at NW Natural primarily due to the following factors:
- $41.7 million increase in NGD segment margin driven by the 2020 Oregon rate case and residential customer growth;
- $7.9 million increase in asset management revenue primarily due to the 2021 cold weather event discussed below; and
- $2.4 million decrease in other income (expense), net driven by higher interest income on regulatory assets and lower pension non-service costs; partially offset by
- $19.9 million increase in operations and maintenance expenses due to higher information technology expenses, compensation and benefit costs, and lease expense;
- $8.9 million increase in depreciation expense due to property, plant, and equipment additions as we continued to invest in our gas utility system;
- $7.2 million increase in income tax expense due to an increase in pretax income and Oregon Corporate Activity Tax;
- $3.7 million increase in general taxes primarily due to higher assessed property values; and
- $2.1 million increase in interest expense primarily due to lower AFUDC interest income.

Net income from continuing operations increased $8.4 million at NW Holdings primarily due to the following factors:
- $10.6 million increase in consolidated net income at NW Natural as discussed above; partially offset by
- $2.2 million decrease in other net income primarily reflecting higher business development and consulting costs at NW Holdings.

2021 COLD WEATHER EVENT. In February 2021, Portland, Oregon and the surrounding region, like much of the country, experienced a severe winter storm with several days of colder temperatures resulting in elevated natural gas demand and significantly higher spot prices. Additional market gas purchases and other expenses resulted in approximately $29 million of higher commodity costs, of which approximately $27 million was deferred to a regulatory asset for recovery in future rates. The result was approximately $2 million of lower natural gas utility margin in the first quarter of 2021. The higher commodity costs were offset by approximately $39 million of asset management revenue, of which approximately $33 million was deferred to a regulatory liability for the benefit of customers. During the first quarter of 2022, NW Natural refunded an interstate storage and asset management sharing credit of approximately $41 million to Oregon customers, which was primarily related to the cold weather event in February 2021.

CURRENT ECONOMIC CONDITIONS. We are evaluating and monitoring current economic conditions, which include but are not limited to: inflation, rising interest rates and commodity costs, recessionary pressures, heightened cybersecurity awareness, geopolitical uncertainty, and supply chain disruptions. We have enhanced cybersecurity monitoring in response to reports that cybersecurity attacks have increased and may continue to increase. We have not experienced material disruptions in our supply chain for goods and services to date. Our suppliers may be subject to lack of personnel or disruption in their own supply chain for materials, which could disrupt supplier performance or deliveries, and negatively impact our business. Developers and HVAC suppliers have reported longer lead times for furnaces and other HVAC equipment, which may affect the timing of placing new meters into service particularly those converting to natural gas. However, because any supply chain issues are being experienced by vendors who supply directly to customers and not us, we do not have visibility of and are not able to quantify the number of new meters affected at this time. We are continuing to actively monitor supply chain disruptions, and have formulated and continue to evaluate contingency plans as necessary.

NW Holdings and NW Natural continue to monitor interest rates and financing options for all of its businesses. Interest rates have increased in 2022 resulting from actions taken by the U.S. Federal Reserve to increase short-term rates as inflation remains elevated. NW Natural generally recovers interest expense on its long-term debt through its authorized cost of capital. Certain working capital items, such as the cost of gas, are deferred and accrue interest in Oregon and Washington. Additionally, short-term debt is incorporated in the capital structure in Washington. NW Natural Water's regulated water and wastewater utilities recover interest expense from long-term debt through their respective authorized cost of capital.

2023 OUTLOOK

At NW Natural Holdings, we remain focused on our mission: to provide safe, reliable and affordable utility services and renewable energy in a sustainable way to better the lives of the communities we serve. Our core values of integrity, safety, service ethic, caring and environmental stewardship are the foundation for our success and fundamental to our mission.

Our common goals for each of our business lines is: build and sustain a diverse and inclusive workforce; execute operational priorities to further support safety and reliability for our employees and customers; pursue net carbon neutral energy and sustainable water solutions for our customers, communities and operations, focus on profitable growth across our companies; and work to advance constructive policy and regulation that serves the interest of customers and supports opportunities for growth.

NW Natural

Delivering our products safely and reliably to customers, while keeping our employees safe, is our first priority. At NW Natural, we remain focused on safety and emergency response through hands-on, scenario-based training for our employees. The reliability, resiliency and safety of our gas system is critical and to this end, we remain focused on investing in necessary maintenance and upgrades, preventing third-party damages, and performing regular inspections and assessments. Safety also includes maintaining and strengthening our cybersecurity defenses, upgrading key technology systems, and preparing for large-scale emergency events, such as seismic hazards.

We have a legacy of providing excellent customer service and a long-standing dedication to continuous improvement, which has resulted in NW Natural consistently receiving high rankings in the J.D. Power and Associates customer satisfaction studies. We plan to continue this legacy by combining the expertise of our customer care and field employees with the benefits of new technologies to provide top-notch customer interactions and meet the evolving expectations of our customers.

We are focused on working productively with lawmakers and regulators. In 2023, we intend to continue proactively communicating with policymakers and other stakeholders about what we believe is the important role of the gas system in achieving climate goals for our communities. With regulators, we continue to strive to work productively on open proceedings.

At the same time, we'll strive to continue growing our business by pursuing and adopting unique energy solutions, executing on our capital investment plans, and managing and promoting adoption of advanced technologies.

We are deeply committed to our core value of environmental stewardship and the vision of a clean energy future. NW Natural has been a leader among gas utilities in innovative programs designed to support a lower carbon future. In 2023, NW Natural intends to continue striving to: execute on our renewable strategy by helping our customers reduce and offset their consumption, work to comply with the Oregon Climate Protection Program (CPP) and Washington Climate Commitment Act (CCA), procure and invest in RNG for our customers, and continue testing hydrogen blending and other hydrogen pilot projects.

NW Natural Water

Our water and wastewater utility business is committed to providing its customers with safe, clean, reliable and affordable water and wastewater services, while growing organically and through acquisitions. These utilities are focused on supporting their fast-growing communities by executing on capital expenditure programs aimed at safety and reliability and filing general rate cases, where needed, to support these investments. In addition, we continue to promote water conservation and sustainable wastewater management through system investments, regulation, policies and customer programs.

NW Natural Renewables

We launched an unregulated business line in 2021 established to invest in renewable energy through the production and supply of lower-carbon fuels. In 2023, we expect to begin earning revenues from the resale of RNG from our first project with EDL, which involves two RNG facilities. We intend to continue pursuing other similar renewable projects and opportunities.

DIVIDENDS

NW Holdings dividend highlights include:

Per common share	2022	2021	2020
Dividends paid	$ 1.9325	$ 1.9225	$ 1.9125

In January 2023, the Board of Directors of NW Holdings declared a quarterly dividend on NW Holdings common stock of $0.4850 per share, payable on February 15, 2023, to shareholders of record on January 31, 2023, reflecting an indicated annual dividend rate of $1.94 per share.

See "Financial Condition - *Liquidity and Capital Resources*" for more information regarding the NW Holdings and NW Natural dividend policies and regulatory conditions on NW Natural dividends to its parent, NW Holdings.

RESULTS OF OPERATIONS

Regulatory Matters

Regulation and Rates

NATURAL GAS DISTRIBUTION. NW Natural's natural gas distribution business is subject to regulation by the OPUC and WUTC with respect to, among other matters, rates and terms of service, systems of accounts, and issuances of securities by NW Natural. In 2022, approximately 88% of NGD customers were located in Oregon, with the remaining 12% in Washington. Earnings and cash flows from natural gas distribution operations are largely determined by rates set in general rate cases and other proceedings in Oregon and Washington. They are also affected by weather, the local economies in Oregon and Washington, the pace of customer growth in the residential, commercial, and industrial markets, customer preferences and NW Natural's ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery of its natural gas distribution-related costs, including operating expenses and investment costs in plant and other regulatory assets. See "*Most Recent Completed Rate Cases*" below.

MIST INTERSTATE GAS STORAGE. NW Natural's interstate storage activity at Mist is subject to regulation by the OPUC, WUTC, and the Federal Energy Regulatory Commission (FERC) with respect to, among other matters, rates and terms of service. The OPUC also regulates the intrastate storage services at Mist, while FERC regulates the interstate storage services at Mist. The FERC uses a maximum cost of service model which allows for gas storage prices to be set at or below the cost of service as approved by each agency in their last regulatory filing. The OPUC intrastate Schedule 80 rates are tied to the FERC rates, and are updated whenever NW Natural modifies FERC maximum rates.

OTHER. The wholly-owned regulated water businesses of NWN Water, a wholly-owned subsidiary of NW Holdings, are subject to regulation by the utility commissions in the states in which they are located, which currently includes Oregon, Washington, Arizona, Idaho, and Texas. The wholly-owned regulated wastewater businesses of NWN Water are subject to regulation by the utility commissions in Texas and Arizona.

Most Recent Completed Rate Cases

OREGON. On October 24, 2022, the OPUC issued an order for rates effective November 1, 2022, which authorized a return on equity of 9.4%, a cost of capital of 6.836%, and a capital structure of 50% common equity and 50% long-term debt. After adjustments provided in the order, the order increased the revenue requirement by $59.4 million, and included a rate base of $1.76 billion, or an increase of $320 million since the last rate case. The OPUC also ordered an adjustment to NW Natural's current line extension allowance methodology to a five times margin approach (which for an average residential customer is currently approximately $2,300), declining to four times margin on November 1, 2023, and three times margin on November 1, 2024. The OPUC further ordered that the costs NW Natural sought to recover related to its Lexington RNG project were reasonable and prudently incurred under Senate Bill 98 and adopted an automatic adjustment clause that allows for NW Natural's RNG project costs to be added to rates annually on November 1st.

From November 1, 2020 through October 31, 2022, the OPUC authorized rates to customers based on an ROE of 9.4% and a cost of capital of 6.965% with a capital structure of 50% common equity and 50% long-term debt. The OPUC also authorized NW Natural to recover the expense associated with the Oregon Corporate Activity Tax (CAT) as a component of base rates. See "*Corporate Activity Tax*" in the 2021 Form 10-K. In addition, the OPUC approved the application of NW Natural's decoupling calculation for the months of November and May to the month of April. The decoupling mechanism is intended to encourage customers to conserve energy without adversely affecting revenue due to reductions in sales volumes.

WASHINGTON. On October 21, 2021, the WUTC issued an order concluding NW Natural's general rate case filed in December 2020 (WUTC Order). The WUTC Order provides for an annual revenue requirement increase over two years, consisting of a 6.4% or $5.0 million increase in the first year beginning November 1, 2021 (Year One), and up to a 3.5% or $3.0 million increase in the second year beginning November 1, 2022 (Year Two). The increase is based on the following assumptions:

- Cost of capital of 6.814%; and
- Average rate base of $194.7 million, an increase of $20.9 million since the last rate case for capital expenditures already expended at the time of filing, with an additional expected $31.2 million increase in Year One, and an additional expected $21.4 million increase in Year Two, with the increases in Year One and Year Two relating to expected capital expenditures in those years.

The WUTC Order does not specify the underlying inputs to the cost of capital, including capital structure and return on equity. New rates authorized by the WUTC Order were effective November 1, 2021.

From November 1, 2019 through October 31, 2021, the WUTC authorized rates to customers based on an ROE of 9.4% and an overall rate of return of 7.161% with a capital structure of 50.0% long-term debt, 1.0% short-term debt, and 49.0% common equity. The WUTC also authorized the recovery of environmental remediation expenses allocable to Washington customers through an Environmental Cost Recovery Mechanism (ECRM) and directed NW Natural to provide federal tax reform benefits to customers. See "Rate Mechanisms - Environmental Cost Deferral and Recovery - *Washington ECRM*" below.

FERC. NW Natural is required under its Mist interstate storage certificate authority and rate approval orders to file every five years either a petition for rate approval or a cost and revenue study to change or justify maintaining the existing rates for its interstate storage services. On October 12, 2018, NW Natural filed a rate petition with FERC for revised cost-based maximum rates, which incorporated the new federal corporate income tax rate. The revised rates were effective beginning November 1, 2018.

NW Natural continuously evaluates the need for rate cases in its jurisdictions.

Rate Mechanisms

During 2022 and 2021, NW Natural's key approved rates and recovery mechanisms for each service area included:

	Oregon		Washington	
	2022 Rate Case (effective 11/1/2022)	2020 Rate Case (effective 11/1/2020)	2021 Rate Case (effective 11/1/2021)	2019 Rate Case (effective 11/1/2019)
Authorized Rate Structure:				
Return on Equity	9.4%	9.4%	**	9.4%
Rate of Return	6.8%	7.0%	6.8%	7.2%
Debt/Equity Ratio	50%/50%	50%/50%	**	51%/49%
Key Regulatory Mechanisms:				
Purchased Gas Adjustment (PGA)	X	X	X	X
Gas Cost Incentive Sharing	X	X		
Decoupling	X	X		
Weather Normalization (WARM)	X	X		
RNG Automatic Adjustment Clause	X			
Environmental Cost Recovery	X	X	X	X
Interstate Storage and Asset Management Sharing	X	X	X	X

** The WUTC Order does not specify the underlying inputs to the cost of capital, including capital structure and return on equity.

Annually, or more often if circumstances warrant, NW Natural reviews all regulatory assets for recoverability. If NW Natural should determine all or a portion of these regulatory assets no longer meet the criteria for continued application of regulatory accounting, then NW Natural would be required to write-off the net unrecoverable balances against earnings in the period such a determination was made.

PURCHASED GAS ADJUSTMENT. Rate changes are established for NW Natural each year under PGA mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases. The PGA filings include gas costs under spot purchases as well as contract supplies, gas cost hedges, gas costs from the withdrawal of storage inventories, the production of gas reserves, interstate pipeline demand costs, renewable natural gas and its attributes, including renewable thermal certificates, temporary rate adjustments, which amortize balances of deferred regulatory accounts, and the removal of temporary rate adjustments effective for the previous year.

Each year, NW Natural hedges gas prices on a portion of NW Natural's annual sales requirement based on normal weather, including both physical and financial hedges. During 2021 and 2022, there was increased price volatility in the spot and forward gas markets. In response to higher than normal volatility in forward gas markets in 2022, we are hedged at higher levels for the 2022-23 gas year. As of December 31, 2022, NW Natural's forecasted sales volume was hedged at approximately 84% in total for the 2022-23 gas year compared to 82% in the 2021-22 PGA year. The total hedged for Oregon was approximately 85%, including 67% in financial hedges and 18% in physical gas supplies. The total hedged for Washington was approximately 79%, including 66% in financial hedges and 13% in physical gas supplies.

NW Natural is hedged in total between 21% and 31% for annual requirements over the subsequent two gas years, which consists of between 23% and 30% in Oregon and between 0% and 45% in Washington. Hedge levels are subject to change based on actual load volumes, which depend to a certain extent on weather, economic conditions, and estimated gas reserve production. Also, gas storage inventory levels may increase or decrease with storage expansion, changes in storage contracts with third parties, variations in the heat content of the gas, and/or storage recall by NW Natural. As the Company planned for the 2022-23 gas year, gas price volatility remained high with current and forward gas prices increasing substantially in 2022. We will continue to monitor gas prices as we begin to fill storage and look at hedging plans for future gas years. Gas purchases and hedges entered into for the upcoming PGA year will be included in the Company's PGA filings in Oregon and Washington.

In September 2022, NW Natural filed its annual PGAs and received OPUC and WUTC approval in October 2022.
Included in the 2022-23 PGA, the OPUC and WUTC approved a new rate mitigation program to address high gas costs, which includes a temporary bill credit for NW Natural's residential customers, beginning November 1, 2022, with deferral of the temporary bill credit to warmer months when customers typically see lower bills. As of December 31, 2022, the amount deferred to a regulatory asset was $11.5 million. PGA rate changes were effective November 1, 2022. Rates may vary between states due to different rate structures, rate mechanisms and hedging policies.

Under the current PGA mechanism in Oregon, there is an incentive sharing provision whereby NW Natural is required to select each year an 80% deferral or a 90% deferral of higher or lower actual gas costs compared to estimated PGA prices, such that the impact on NW Natural's current earnings from the incentive sharing is either 20% or 10% of the difference between actual and estimated gas costs, respectively. For the 2021-22 and 2022-23 gas years, NW Natural selected the 90% deferral option. Under the Washington PGA mechanism, NW Natural defers 100% of the higher or lower actual gas costs, and those gas cost differences are passed on to customers through the annual PGA rate adjustment.

EARNINGS TEST REVIEW. NW Natural is subject to an annual earnings review in Oregon to determine if the NGD business is earning above its authorized ROE threshold. If NGD business earnings exceed a specific ROE level, then 33% of the amount above that level is required to be deferred or refunded to customers. Under this provision, if NW Natural selects the 80% deferral gas cost option, then NW Natural retains all earnings up to 150 basis points above the currently authorized ROE. If NW Natural selects the 90% deferral option, then it retains all earnings up to 100 basis points above the currently authorized ROE. For the 2021-22 and 2022-23 gas years, NW Natural selected the 90% deferral option. The ROE threshold is subject to adjustment annually based on movements in long-term interest rates. For calendar years 2020, 2021, and 2022, the ROE threshold was 10.40% in all periods. There were no refunds required for 2020 and 2021. NW Natural does not expect a refund for 2022 based on results, and anticipates filing its 2022 earnings test in May 2023.

GAS RESERVES. In 2011, the OPUC approved the Encana gas reserves transaction to provide long-term gas price protection for NGD business customers and determined costs under the agreement would be recovered on an ongoing basis through the annual PGA mechanism. Gas produced from NW Natural's interests is sold at then prevailing market prices, and revenues from such sales, net of associated operating and production costs and amortization, are included in cost of gas. The cost of gas, including a carrying cost for the rate base investment made under the original agreement, is included in NW Natural's annual Oregon PGA filing, which allows NW Natural to recover these costs through customer rates. The net investment under the original agreement earns a rate of return.

In 2014, NW Natural amended the original gas reserves agreement in response to Encana's sale of its interest in the Jonah field located in Wyoming to Jonah Energy. Under the amended agreement with Jonah Energy, NW Natural has the option to invest in additional wells on a well-by-well basis with drilling costs and resulting gas volumes shared at the amended proportionate working interest for each well in which NW Natural invests. Volumes produced from the additional wells drilled after the amended agreement are included in NW Natural's Oregon PGA at a fixed rate of $0.4725 per therm. NW Natural has not participated in additional wells since 2014.

DECOUPLING. In Oregon, NW Natural has a decoupling mechanism. Decoupling is intended to break the link between revenue and the quantity of gas consumed by customers, removing any financial incentive to discourage customers' efforts to conserve energy. The Oregon decoupling baseline usage per customer was reset in the 2020 Oregon general rate case. The Order in the 2020 Oregon general rate case also approved of extending NW Natural's decoupling calculation for the months of November and May to the month of April. This mechanism employs a use-per-customer decoupling calculation, which adjusts margin revenues to account for the difference between actual and expected customer volumes. The margin adjustment resulting from differences between actual and expected volumes under the decoupling component is recorded to a deferral account, which is included in the annual PGA filing.

WARM. In Oregon, NW Natural has an approved weather normalization mechanism (WARM), which is applied to residential and small commercial customer bills. This mechanism is designed to help stabilize the collection of fixed costs by adjusting residential and small commercial customer billings based on temperature variances from average weather, with rate decreases when the weather is colder than average and rate increases when the weather is warmer than average. The mechanism is applied to bills from December through mid-May. The mechanism adjusts the margin component of customers' rates to reflect average weather, which uses the 25-year average temperature for each day of the billing period. Daily average temperatures and 25-year average temperatures are based on a set point temperature of 59 degrees Fahrenheit for residential customers and 58 degrees Fahrenheit for commercial customers. The collections of any unbilled WARM amounts due to tariff caps and floors are deferred and earn a carrying charge until collected, or returned, in the PGA the following year. Residential and small commercial customers in Oregon are allowed to opt out of the weather normalization mechanism, and as of December 31, 2022, 7% of total eligible customers had opted out. NW Natural does not have a weather normalization mechanism approved for Washington customers, which account for about 12% of total customers. See "Business Segment—*Natural Gas Distribution*" below.

INDUSTRIAL TARIFFS. The OPUC and WUTC have approved tariffs covering NGD service to major industrial customers, which are intended to give NW Natural certainty in the level of gas supplies needed to serve this customer group. The approved terms include, among other things, an annual election period, special pricing provisions for out-of-cycle changes, and a requirement that industrial customers complete the term of their service election under NW Natural's annual PGA tariff.

ENVIRONMENTAL COST DEFERRAL AND RECOVERY. NW Natural has authorizations in Oregon and Washington to defer costs related to remediation of properties that are owned or were previously owned by NW Natural. In Oregon, a Site Remediation and Recovery Mechanism (SRRM) is currently in place to recover prudently incurred costs allocable to Oregon customers, subject to an earnings test. Effective beginning November 1, 2019, the WUTC authorized an Environmental Cost Recovery Mechanism (ECRM) for recovery of prudently incurred costs allocable to Washington customers.

Oregon SRRM

Under the Oregon SRRM collection process, there are three types of deferred environmental remediation expense:

- Pre-review - This class of costs represents remediation spend that has not yet been deemed prudent by the OPUC. Carrying costs on these remediation expenses are recorded at NW Natural's authorized cost of capital. NW Natural anticipates the prudence review for annual costs and approval of the earnings test prescribed by the OPUC to occur by the third quarter of the following year.
- Post-review - This class of costs represents remediation spend that has been deemed prudent and allowed after applying the earnings test, but is not yet included in amortization. NW Natural earns a carrying cost on these amounts at a rate equal to the five-year treasury rate plus 100 basis points.
- Amortization - This class of costs represents amounts included in current customer rates for collection and is calculated as one-fifth of the post-review deferred balance. NW Natural earns a carrying cost equal to the amortization rate determined annually by the OPUC, which approximates a short-term borrowing rate. NW Natural included $6.8 million and $6.3 million of deferred remediation expense approved by the OPUC for collection during the 2022-23 and 2021-22 PGA years, respectively.

In addition, the SRRM also provides for the annual collection of $5.0 million from Oregon customers through a tariff rider. As it collects amounts from customers, NW Natural recognizes these collections as revenue net of any earnings test adjustments and separately amortizes an equal and offsetting amount of the deferred regulatory asset balance through the environmental remediation operating expense line shown separately in the operating expenses section of the Consolidated Statements of Comprehensive Income (Loss). See Note 17 for more information on our environmental matters.

The SRRM earnings test is an annual review of adjusted NGD ROE compared to authorized NGD ROE. To apply the earnings test NW Natural must first determine what if any costs are subject to the test through the following calculation:

Annual spend
Less: $5.0 million base rate rider
Prior year carry-over[1]
$5.0 million insurance + interest on insurance
Total deferred annual spend subject to earnings test
Less: over-earnings adjustment, if any
Add: deferred interest on annual spend[2]
Total amount transferred to post-review

(1) Prior year carry-over results when the prior year amount transferred to post-review is negative. The negative amount is carried over to offset annual spend in the following year.
(2) Deferred interest is added to annual spend to the extent the spend is recoverable.

To the extent the NGD business earns at or below its authorized ROE as defined in the SRRM, the total amount transferred to post-review is recoverable through the SRRM. To the extent more than authorized ROE is earned in a year, the amount transferred to post-review would be reduced by those earnings that exceed its authorized ROE.
For 2022, NW Natural has performed this test, which is anticipated to be submitted to the OPUC in May 2023. No earnings test adjustment is expected for 2022.

Washington ECRM

The ECRM established by the WUTC order effective November 1, 2019 permits NW Natural’s recovery of environmental remediation expenses allocable to Washington customers. These expenses represent 3.32% of costs associated with remediation of sites that historically served both Oregon and Washington customers. The order allows for recovery of past deferred and future prudently incurred remediation costs allocable to Washington through application of insurance proceeds and collections from customers. Prudently incurred costs that were deferred from the initial deferral authorization in February 2011 through June 2019 are to be fully offset with insurance proceeds, with any remaining insurance proceeds to be amortized over a 10.5 year period. On an annual basis, NW Natural will file for a prudence determination and a request to recover remediation expenditures in excess of insurance amortizations in the following year's customer rates. After insurance proceeds are fully amortized, if in a particular year the request to collect deferred amounts exceeds one percent of Washington normalized revenues, then the excess will be collected over three years with interest.

INTERSTATE STORAGE AND ASSET MANAGEMENT SHARING. On an annual basis, NW Natural credits amounts to Oregon and Washington customers as part of a regulatory incentive sharing mechanism related to net revenues earned from Mist gas storage and asset management activities. In January 2023, the OPUC approved the annual 2023 bill credit for Oregon customer’s share of interstate storage and asset management activities totaling approximately $23.5 million. This includes revenue generated for the November 2021 through October 2022 PGA year. Commercial and industrial customers in Oregon will receive this credit in February 2023. Residential customers in Oregon will receive this credit as a reduction to the temporary rate mitigation adjustment, which begins in March 2023. Credits are given to customers in Washington as reductions in rates through the annual PGA filing in November.

During the first quarter of 2022, NW Natural refunded an interstate storage and asset management sharing credit of approximately $41.1 million to Oregon customers over three equal installments in January, February and March. This includes revenue generated for the November 2020 through October 2021 PGA year. A majority of this revenue is from the cold weather event in February 2021 discussed above.

The following table presents the credits to NGD customers:

In millions	2022	2021	2020
Oregon	$ 41.1	$ 9.1	$ 17.0
Washington	$ 1.5	$ 3.1	$ 0.7

COVID-19 PROCESS AND DEFERRAL DOCKETS. During 2020, Oregon and Washington approved our applications to defer certain COVID-19 related costs. Costs that may be recoverable include, but are not limited to, the following: personal protective equipment, cleaning supplies and services, bad debt expense, financing costs to secure liquidity, and certain lost revenue, net of offsetting direct expense reductions associated with COVID-19. As of December 31, 2022, we believe that approximately $18.7 million of the financial effects related to COVID-19 are recoverable. As part of the 2022 Oregon general rate case, NW Natural received approval from the OPUC to recover the 2020 and 2021 COVID-19 deferral beginning November 1, 2022. Approximately $10.9 million will be amortized over a two-year period and NW Natural may request recovery of the remaining amount in the third year. Included in the total balance is approximately $3.4 million of forgone late fee revenue that will be recognized in future periods when billed. Beginning January 2023, NW Natural will no longer defer any COVID-19 related costs in Oregon. NW Natural expects to recover its COVID-19 deferrals in Washington in a future proceeding.

The following table outlines some of the key items approved by the respective Commissions:

	Oregon	Washington
Reinstituting Disconnections for Nonpayment:		
Residential	August 1, 2021	September 30, 2021
Small Commercial	December 1, 2020	September 30, 2021
Large Commercial/Industrial	November 3, 2020	October 20, 2020
Resuming Residential Reconnection Fee Charges	October 1, 2022	**
Reinstituting Late Fees for Nonpayment:		
Residential	October 1, 2022	**
Small Commercial	December 1, 2020	**
Large Commercial/Industrial	November 3, 2020	October 20, 2020
Arrearage Management Program	1.5% of Retail Revenue	1% of Retail Revenue

** Date is pending a Commission review of its existing credit and collection practices that is expected to be completed over the next year.

ARREARAGE MANAGEMENT PROGRAMS. As part of the approved term sheets, NW Natural established programs in Oregon and Washington to identify and mitigate residential customer arrearages associated with COVID-19. Under the Washington program, income-eligible customers may receive up to $2,500 per year. In March 2022, the Oregon program was expanded to include additional funding and a low-income focus. AMP is funded by NW Natural with recovery facilitated through the COVID-19 deferral dockets. During 2022, NW Natural granted $9.4 million of the total funds available of $9.9 million. The programs in both Oregon and Washington are now closed.

LOW INCOME DISCOUNT TARIFF. In July 2022, NW Natural received approval from the OPUC for an income-qualifying residential bill discount program. The income threshold for program participation is at or below 60 percent of Oregon state median income (SMI). The program provides a bill discount for income-qualifying residential customers at four discount tier levels based on household income compared to SMI, with higher discounts given for lower income levels. Participating customers can self-certify their income and household size to qualify for the program directly with NW Natural or their local Community Action Agency. The program was available for qualifying customers starting November 1, 2022. Costs for the bill discount program include simultaneous recovery from all customers. Costs for the bill discount program, inclusive of start-up and administrative costs of the program, are recoverable in rates. The amount deferred to a regulatory asset as of December 31, 2022 was not significant.

	Total Household Income	Bill Discount Percentage
Tier 0	At or below 15% SMI	40%
Tier 1	16% - 30% of SMI	25%
Tier 2	31% - 45% of SMI	20%
Tier 3	46% - 60% of SMI	15%

RENEWABLE NATURAL GAS AND AUTOMATIC ADJUSTMENT CLAUSE. On June 19, 2019, the Oregon legislature passed Senate Bill 98 (SB 98), which enables natural gas utilities to procure or develop RNG on behalf of their Oregon customers. The bill was signed into law by the governor in July 2019, and subsequently, the OPUC opened a docket in August 2019 regarding the rules for the bill. After working with parties, the OPUC adopted final rules in July 2020.

SB 98 and the rules outline the following parameters for the RNG program including: setting voluntary goals for adding as much as 30% renewable natural gas into the state's pipeline system by 2050; enabling gas utilities to invest in and own the cleaning and conditioning equipment required to bring raw biogas and landfill gas up to pipeline quality, as well as the facilities to connect to the local gas distribution system; and allowing up to 5% of a utility's revenue requirement to be used to cover the incremental cost or investment in renewable natural gas infrastructure.

Further, the new law supports all forms of renewable natural gas including renewable hydrogen, which is made from excess wind, solar and hydro power. Renewable hydrogen can be used for the transportation system, industrial use, or blended into the natural gas pipeline system.

Pursuant to the 2022 Oregon general rate case, the OPUC ordered that the costs NW Natural sought to recover related to its investment in Lexington Renewables Energy, LLC were reasonable and prudently incurred under SB 98. Furthermore, the OPUC approved an automatic adjustment clause that allows for NW Natural's investments in RNG projects, including operating costs, to be added to rates annually on November 1st, following a prudence review. The mechanism allows NW Natural to defer for recovery or credit the differences between the forecasted and actual costs of the RNG projects, subject to an earnings test that includes deadbands at 50 basis points below and above NW Natural's authorized ROE. For RNG procurement contracts, NW Natural seeks recovery of the costs in the PGA, subject to a prudence review.

CORPORATE ACTIVITY TAX. In 2019, the State of Oregon enacted a Corporate Activity Tax (CAT) that is applicable to all businesses with annual Oregon gross revenue in excess of $1 million. The CAT is in addition to the state's corporate income tax and imposes a 0.57% tax on certain Oregon gross receipts less a reduction for a portion of cost of goods sold or labor. The CAT legislation became effective September 29, 2019 and applied to calendar years beginning January 1, 2020. Under the terms of the Order in NW Natural's 2020 Oregon general rate case, NW Natural is authorized to begin to recover the expense associated with the CAT as a component of base rates. NW Natural is also directed to adjust the amount recovered for the CAT in each annual PGA to reflect changes in gross revenue and cost of goods sold that occur as a result of the PGA.

The Order also provides for certain adjustments if there are legislative, rulemaking, judicial, or policy decisions that would cause the calculation methodology used by NW Natural for the CAT to vary in a fundamental way. Additionally, the CAT deferred from January 2020 through June 2020 was added to and amortized over the 2020-21 PGA gas year, and the CAT amounts deferred from July 2020 through the effective date of the rate case were amortized over the 2021-22 PGA year.

INTEGRATED RESOURCE PLAN (IRP). NW Natural generally files a full IRP biennially for Oregon and Washington with the OPUC and WUTC, respectively. NW Natural jointly filed its 2022 IRP for both Oregon and Washington on September 23, 2022. The 2022 IRP outlines scenarios of future requirements based on a range of outcomes that would provide the least-cost and least-risk resources to meet future demand and environmental compliance obligations. In our most recent filing, we included certain demand and supply side projects that resulted in action plan items which will be evaluated by the OPUC and WUTC. With respect to IRPs generally, the WUTC issues letters of compliance and Oregon acknowledges the IRP. NW Natural anticipates the OPUC and WUTC will take such actions by September 30, 2023.

The development of an IRP filing is an extensive and complex process that engages multiple stakeholders in an effort to build a robust and commonly understood analysis. The final product is intended to provide a long-term outlook of the supply-side and demand-side resource requirements for reliable and low cost natural gas service while also meeting NW Natural's environmental compliance requirements. The IRP examines and analyzes uncertainties in the planning process, including potential changes in governmental and regulatory policies. The CPP in Oregon, as well as the CCA that was passed in Washington, are examples of new policies that result in compliance requirements that need to be included in the planning process.

PIPELINE SECURITY. In May and July 2021, the Department of Homeland Security's (DHS) Transportation Security Administration (TSA) released two security directives applicable to certain owners and operators of natural gas pipeline facilities (including local distribution companies). The first directive require owners and operators to implement cybersecurity incident reporting to the DHS, designate a cybersecurity coordinator, and perform a gap assessment of current entity cybersecurity practices against certain voluntary TSA security guidelines and report relevant results and proposed mitigation to applicable DHS agencies. The second directive requires entities to implement a significant number of specified cyber security controls and processes. The TSA recently released a third directive renewing the second directive as well as clarifying Operational Technology (OT) scope and providing a risk- and outcome-based framework. The third directive is effective until July 2023. NW Natural is currently evaluating and implementing the security directives and related deliverables. NW Natural frequently updates the TSA on its progress on achieving the security directives.

NW Natural filed requests with the OPUC and WUTC to defer the costs associated with complying with the TSA's security directives. As of December 31, 2022, NW Natural has invested $33.0 million in information and operational technology and has deferred to a regulatory asset $6.3 million of related costs. A majority of the capital investment was included in rate base starting November 1, 2022 in Oregon.

NW Natural continues to evaluate the potential effect of these directives on our operations and facilities, as well as the potential total cost of implementation, and will continue to monitor for any clarifications or amendments to these directives. We may seek to request recovery from customers of any additional costs incurred to the extent that incremental expenses and capital expenditures are incurred in the future.

ERP UPGRADE DEFERRALS. In the fourth quarter of 2020, NW Natural filed requests to defer expenses pertaining to a project to upgrade the existing enterprise resource planning (ERP) system with the OPUC and WUTC. A stipulation supported by all parties in the Oregon docket was filed and approved by the OPUC in the third quarter of 2021. Under the settlement agreement, NW Natural will recover 100% of costs incurred up to the $8.55 million estimate of Oregon-allocated costs provided in the docket. Approval of the Washington deferral was resolved as part of the most recent general rate case. NW Natural placed its new ERP system into service in September 2022. As of December 31, 2022, NW Natural deferred to a regulatory asset $9.4 million of expenses incurred to date. On November 1, 2022, NW Natural began recovering all expenses deferred and accruing interest over a 10-year period.

FACT-FINDING DOCKET. NW Natural was engaged in an OPUC Fact-Finding (“Fact-Finding Docket”), opened in response to the executive order issued by the Governor of Oregon, for the purpose of analyzing the potential natural gas utility bill impacts that may result from the ODEQ’s CPP and to identify appropriate regulatory tools to mitigate potential customer impacts. The OPUC Staff indicated that the ultimate goal of the Fact-Finding Docket is to inform future policy decisions and other key analyses. OPUC Staff’s final report was issued on January 31, 2023. The report has a number of recommendations concerning the further investigation of regulatory tools, including: 1) expanded energy efficiency programs, 2) additional analysis in future Integrated Resource Plans of decarbonization measures and trends, and 3) additional rate protections for customers. The OPUC has since closed the Fact-Finding Docket without taking any action on Staff’s final report.

WATER UTILITIES. NWN Water currently serves an estimated 155,000 people through approximately 62,500 connections across five states. NWN Water, through one or more of its subsidiaries, acquired an increased ownership stake in Avion Water Company in Oregon to 40.3%, and acquired the assets of five regulated businesses during 2022, after receiving approval from the respective public utility commissions.

For our regulated water utilities, we have been executing general rate cases.

- In January 2022, we filed a general rate case for Suncadia Water and the WUTC allowed rates to go into effect in May 2022 by operation of law.
- In February 2022, the OPUC adopted a comprehensive stipulation in Sunriver Water's rate case with new rates effective May 2022.
- In June 2022, Avion Water Company filed a general rate case with the OPUC and the OPUC allowed rates to go into effect January 1, 2023.
- In July 2022, Gem State Water Company filed a general rate case with the IPUC and a decision is expected in the first half of 2023.

Environmental Regulation and Legislation Matters

There is a growing international and domestic focus on climate change and the contribution of GHG emissions, most notably methane and carbon dioxide, to climate change. In response, there are increasing efforts at the international, federal, state, and local level to regulate GHG emissions. Legislation or other forms of regulation could take a variety of forms including, but not limited to, GHG emissions limits, reporting requirements, carbon taxes, requirements to purchase carbon credits, building codes, increased efficiency standards, additional charges to fund energy efficiency activities or other regulatory actions, incentives or mandates to conserve energy, or use renewable energy sources, tax advantages and other subsidies to support alternative energy sources, a reduction in rate recovery for construction costs related to the installation of new customer services or other new infrastructure investments, mandates for the use of specific fuels or technologies, bans on specific fuels or technologies, or promotion of research into new technologies to reduce the cost and increase the scalability of alternative energy sources. These efforts could include legislation, legislative proposals, or new regulations at the federal, state, and local level, as well as private party litigation related to GHG emissions. We recognize certain of our businesses, including our natural gas business, are likely to be affected by current or future regulation seeking to limit GHG emissions.

International

In early 2021, the U.S. rejoined the Paris Agreement on Climate, which establishes non-binding targets to reduce GHG emissions from both developed and developing nations. Under the Paris Agreement, signatory countries are expected to submit their nationally determined contributions to curb GHG emissions and meet the agreed temperature objectives every five years. On April 22, 2021, the United States federal administration announced the U.S. nationally determined contribution to achieve a fifty to fifty-two percent reduction from 2005 levels in economy-wide net GHG emissions by 2030.

Federal

President Biden’s administration has issued executive orders directing agencies to conduct a general review of regulations and executive actions related to the environment and reestablished a framework for considering the social cost of carbon as part of certain agency cost-benefit analyses for new regulations. President Biden's administration continues to consider a wide range of additional policies, executive orders, rules, legislation, and other initiatives to address climate change.

The Inflation Reduction Act of 2022 (IRA) was signed into law in August 2022 and includes several climate and energy provisions. We expect that over a ten year period, the IRA will provide approximately $415 billion of funding through grants, tax credits, and investments to support various initiatives including manufacturing, renewable energy production and consumption, transportation electrification and climate-smart agriculture. The IRA includes tax credits for RNG, hydrogen and carbon capture projects, among other investments. The IRA also includes funding for the EPA to improve GHG reporting and enforcement, as well as a methane fee applicable to activities associated with gas production and processing facilities, transmission pipelines and certain storage facilities, creates a new corporate alternative minimum tax of 15 percent that applies to corporations with average annual financial statement income in excess of one billion dollars, and creates a new 1 percent excise tax on the net stock repurchases by public companies. We are assessing effects of the IRA that are relevant to our businesses, and will continue to do so as it is implemented. The U.S. Congress may also pass federal climate change legislation in the future. We cannot predict when or if Congress will pass such legislation and in what form.

In addition, the EPA regulates GHG emissions pursuant to the Clean Air Act. For example, the EPA requires the annual reporting of greenhouse gas emissions from certain industries, specified emission sources, and facilities. Under this reporting rule, local natural gas distribution companies like NW Natural are required to report system throughput to the EPA on an annual basis. The EPA also has required additional GHG reporting regulations to which NW Natural is subject, requiring the annual reporting of fugitive emissions from operations. Other federal regulatory agencies, including the U.S. Department of Energy and Federal Energy Regulatory Commission, are beginning to address greenhouse gas emissions that may include changes in their regulatory oversight approach, policies and rules.

Other federal agencies have taken or are expected to take actions related to climate change. For example, in March 2022, the Securities and Exchange Commission (SEC) proposed new rules relating to the disclosure of a range of climate-related matters, PHMSA is expected to prepare regulations and other actions to limit methane emissions, the Commodities Futures Trading Commission (CFTC) has indicated it intends to take actions related to oversight of climate-related financial risks as pertinent to the derivatives and underlying commodities markets. Similarly, other federal agencies and regulations, including but not limited to the Consumer Products Safety Commission, the U.S. Department of Treasury, Federal Acquisitions Regulations, and others have indicated impending regulatory actions related to climate change. To the extent these agencies adopt final rules as proposed or in modified form, we or our customers could incur increased costs. These could include internal costs as well as external costs such as the cost of independent experts to provide attestation reports on our GHG emissions data and increased audit costs.

Washington State

In 2022, Washington comprised approximately 12% of NW Natural's revenues, as well as 1% and 18% of new meters from commercial and residential customers, respectively. Effective February 1, 2021, building codes in Washington state require new residential homes to achieve higher levels of energy efficiency based on specified carbon emissions assumptions, which calculate electric appliances to have lower on-site GHG emissions than comparable gas appliances. This increases the cost of new home construction incorporating natural gas depending on a number of factors including home size, equipment configurations, and building envelope measures. Additionally, the Washington State Building Code Council (SBCC) voted in April 2022 to include updates in the state commercial building energy code that are expected to restrict or eliminate the use of gas space and water heating in new commercial construction. In early November, the SBCC voted to include updates to the state residential building energy code that are expected to restrict the use of gas space and water heating in residential construction, with certain exceptions including for natural gas-fired heat pumps and hybrid fuel systems. The SBBC commercial and residential rules are expected to become effective July 1, 2023. Utilities and other organizations, including NW Natural, are reviewing the proposed building energy code updates, the process by which the updates have been considered, and the legality of the building code updates. We expect the building code changes to be subject to legal challenge.

Washington has also enacted the Climate Commitment Act (CCA), which establishes a comprehensive program that includes an overall limit for GHG emissions from major sources in the state that declines yearly beginning January 1, 2023, resulting in an overall reduction of GHG emissions to 95% below 1990 levels by 2050. The Washington Department of Ecology has adopted rules to create a cap-and-invest program, under which entities, including natural gas and electric utilities, large manufacturing facilities, and transportation and other fuel providers, which are subject to the CCA must either reduce their emissions, purchase qualifying offsets (including RNG) or obtain allowances to cover any remaining emissions. NW Natural is subject to the CCA and intends to pursue inclusion of CCA compliance costs in rates.

Oregon

On March 10, 2020, the governor of Oregon issued an executive order (EO) establishing GHG emissions reduction goals of at least 45% below 1990 emission levels by 2035 and at least 80% below 1990 emission levels by 2050 and directed state agencies and commissions to facilitate such GHG emission goals targeting a variety of sources and industries. Although the EO does not specifically direct actions of natural gas distribution businesses, the OPUC is directed to prioritize proceedings and activities that advance decarbonization in the utility sector, mitigate the energy burden experienced by utility customers and ensure system reliability and resource adequacy. The EO also directs other state agencies, including the Oregon Department of Environmental Quality (ODEQ), to cap and reduce GHG emissions from transportation fuels and all other liquid and gaseous fuels, including natural gas, adopt building energy efficiency goals for new building construction, reduce methane gas emissions from landfills and food waste, and submit a proposal for adoption of state goals for carbon sequestration and storage by Oregon's forest, wetlands and agricultural lands. The OPUC is charged with carrying out the EO to the extent it is consistent with its statutory authority and duties, and in doing so to focus on equitable impacts to low-income customers.

In December 2021, the ODEQ concluded its rulemaking process and issued final cap and reduce rules for its Climate Protection Program (CPP), which became effective in January of 2022. The CPP outlines GHG emissions reduction goals of 50% by 2035 and 90% by 2050 from a 1990 baseline. The first three-year compliance period is 2022 through 2024. NW Natural is subject to the CPP, and pursuant to this rule, is required to make its first compliance filing in 2025. We intend to pursue inclusion of compliance costs for the CPP in rates. The CPP has been subject to legal challenge by a number of utilities, companies and organizations, including NW Natural.

Local Jurisdictions and Other Advocacy

In addition to legislative activities at the state level, advocacy groups have indicated a willingness to pursue ballot measures. Some local and county governments in the United States also have been proposing or passing renewable energy resolutions, restrictions, taxes, or fees seeking to accelerate climate action goals. A number of cities across the country, and several in our service territory are taking action or currently considering actions such as limitations or bans on the use of natural gas in new construction or otherwise. For example, in February 2023, the Eugene City Council passed an ordinance that prohibits the use of natural gas in low rise residential buildings beginning with permits submitted after June of 2023. Similarly, some jurisdictions and advocates are seeking to ban the use of natural gas and certain natural gas appliances inside homes and contend that there are detrimental indoor public health effects associated with the use of natural gas.

NW Natural is actively engaged with federal, state and local policymakers, consumers, customers, small businesses and other business coalitions, economic development practitioners, and other advocates in our service territory and is working with these communities to communicate the role that direct use natural gas, and in the coming years, RNG and hydrogen, can play in pursuing more effective policies to reduce GHGs while supporting reliability, resiliency, energy choice, equity, and energy affordability.

NW Natural Decarbonization Initiatives & Compliance Actions

Our customers are currently paying less for their natural gas today than they did 15 years ago. We expect that compliance with any form of regulation of GHG emissions, including the CPP in Oregon and CCA in Washington as well as voluntary actions under SB 98 or otherwise, will require additional resources and compliance tools, and will increase costs. The developing and changing implementation guidance for the CCA and CPP, evolving carbon credit markets and other compliance tool options, decades-long timeframes for compliance, likely changing and evolving laws and energy policy, and evolving technological advancements, all make it difficult to accurately predict long-term tools for and costs of compliance. In September 2022, NW Natural filed its integrated resource plans (IRPs) with the OPUC and WUTC. Those IRPs comprehensively evaluate resource options available to serve NW Natural's customers' energy, capacity and environmental compliance needs. The resources selected for compliance with the CPP and CCA, and therefore the costs associated with those resources are, in part, dependent upon the resolution of our IRP dockets and the resources selected. While we have modeled compliance with the CCA and CPP in our IRPs, given the recency of the adoption of the final CPP and CCA rules and changing guidance with respect to those rules, the nature of our compliance obligations, the manner in which we intend to comply, and the expected costs of compliance are uncertain and subject to significant change, particularly after the first compliance period, and especially with respect to the CPP, under which programs are still being developed. For the first compliance period under the CCA, we currently anticipate that we will comply by purchasing RNG or attributes to reduce emissions, making full use of offsets available under the CCA, meeting remaining compliance requirements by purchasing allowances through the processes outlined under the CCA, and returning all money received from the sale of free carbon allowances to customers. We intend to pursue costs of compliance with the CCA in rates, and currently believe that the costs to comply could increase non-low income residential bills by an estimated 1.5% to 6% in the first year of compliance.

The CPP in Oregon is largely tied to the volume of natural gas consumed and as such, we currently expect that CPP cost impacts will be the lowest among residential customers because they generally consume less, and highest among industrial customers that use significantly higher volumes of natural gas, with cost increases for commercial customers falling between residential and industrial customers. We currently expect that the majority of our needed emissions reduction in Oregon for the first CPP compliance period of 2022-2025 can be met with purchases of RNG or its attributes, with modest supplemental purchases of Community Climate Investments (CCIs) when that program becomes available. We intend to pursue costs of compliance costs with the CPP in rates and currently believe those costs could increase non-low income residential bills by an estimated 1% to 9% in the first compliance period.

These projected customer bill impacts of the CCA and CPP are estimates, are likely to increase beyond the first compliance period, and are subject to change as these laws are implemented and compliance begins. The costs are also likely to vary significantly based on forecasting assumptions related to permitted levels of rate recovery, available technologies and equipment, weather patterns and gas usage, customer growth or attrition, allocation of fixed costs among classes of customers, energy efficiency levels, availability, use and cost of renewables, feasibility of broad-scale hydrogen in the natural gas system, and a number of other assumptions used in the complex analysis of integrated resource planning.

We are not currently able to quantify the extent to which current and prospective building code changes, other limitations on natural gas use, or declining line extension allowances provided in rates to cover construction costs for new services, will affect new meter additions, or to what extent carbon compliance costs included in rates will affect the competitiveness of our business and the demand for natural gas service. All of these developments could negatively affect our gas utility customer growth. However, at the same time natural gas utilities will be subject to GHG emissions regulation, we expect that other energy source providers will be subject to similar, or in some cases stricter or more rapid, compliance requirements that are likely to affect their cost and competitiveness relative to natural gas as well. For example, President Biden has announced his intention to have a carbon-free electricity sector by 2035, 15 years before the target date of the CCA or CCP. In June 2021, the State of Oregon enacted HB 2021, a clean electricity bill that requires the state’s two largest investor-owned electric utilities and retail electricity service suppliers to reduce GHG emissions associated with electricity sold to Oregon customers to 100 percent below baseline levels by 2040 with interim steps, including an 80 percent reduction by 2030 and 90 percent reduction by 2035. This bill does not replace the separate renewable portfolio standards previously established in Oregon, which sets requirements for how much of the electricity used in Oregon must come from renewable resources. In Washington, SB 5116, the Clean Energy Transformation Act, requires all electric utilities in Washington to transition to carbon-neutral electricity by 2030 and to 100 percent carbon-free electricity by 2045. We expect compliance with these and other laws will increase the cost of energy for electric customers in our service territory. We are not able to determine at this time whether increased electricity costs will make natural gas use more or less competitive on a relative basis.

We expect these and other trends to drive innovation of, and demand for, technological developments and innovative new products that reduce GHG emissions. Research and development are occurring across the energy sector, including in the gas sector with work being conducted on gas-fired heat pumps, higher efficiency water and space heating appliances including hybrid systems, carbon capture utilization and storage developments, continued development of technologies related to RNG, and various forms of hydrogen for different applications, among others.

NW Natural continues to take proactive steps in seeking to reduce GHG emissions in our region and is proactively communicating with local, state, and federal governments and communities about those steps. NW Natural has been a leader among gas utilities in innovative programs. Notable programs have included a decoupling rate structure designed to weaken the link between revenue and gas consumption by customer adopted in 2007, and establishment of a voluntary Smart Energy carbon offset program for customers established in 2007, and removal of all known cast iron and bare steel to create one of the tightest and most modern distribution systems in the country. We continue to believe that NW Natural has an important role in providing affordable and equitable energy to the communities we serve. NW Natural is an important provider of energy to families and businesses in Oregon and southwest Washington. Natural gas sales to our residential and commercial customers account for approximately 6% of Oregon’s GHG emissions according to the 2019 data from the State of Oregon Department of Environmental Quality In-Boundary GHG Inventory. We intend to continue to provide this necessary energy to our communities with the goal of using our modern pipeline system to help the Pacific Northwest transition to a clean energy future.

In 2016, NW Natural initiated a multi-pronged, multi-year strategy to accelerate and deliver greater GHG emission reductions in the communities we serve. Key components of this strategy include customer energy efficiency, continued adoption of NW Natural's voluntary Smart Energy carbon offset program, and seeking to incorporate RNG and hydrogen into our gas supply. RNG is produced from organic materials including food, agricultural and forestry waste, wastewater, or landfills. We believe RNG has the potential to significantly reduce net GHG emissions because methane that would otherwise be released to the atmosphere can be captured from these organic materials as they decompose and then conditioned to pipeline quality and distributed into our existing system. In 2019, Oregon Senate Bill 98 (SB 98) was signed into law enabling NW Natural to procure RNG on behalf of customers and provided voluntary targets that would allow us to make qualified investments and purchase RNG from third parties.

Under SB 98, NW Natural is actively working to procure RNG supply for customers and increase the amount of RNG on our system and is also exploring the development of renewable hydrogen through power to gas. To that end, in 2020 and 2021, NW Natural announced several agreements and investments to procure RNG for its customers. For example, NW Natural began a partnership with BioCarbN to invest up to an estimated $38 million in four separate RNG development projects that will access biogas derived from water treatment at Tyson Foods’ processing plants, subject to approval by all parties. The first project was commissioned in early 2022 with a second underway and planned to be commissioned in early 2023. To date, NW Natural has signed agreements with options to purchase or develop RNG for utility customers totaling about 3% of NW Natural’s annual sales volume in Oregon.

Business Segment - Natural Gas Distribution (NGD)

NGD margin results are primarily affected by customer growth, revenues from rate-base additions, and, to a certain extent, by changes in delivered volumes due to weather and customers’ gas usage patterns. In Oregon, NW Natural has a conservation tariff (also called the decoupling mechanism), which adjusts margin up or down each month through a deferred regulatory accounting adjustment designed to offset changes resulting from increases or decreases in average use by residential and commercial customers. NW Natural also has a weather normalization tariff in Oregon, WARM, which adjusts customer bills up or down to offset changes in margin resulting from above- or below-average temperatures during the winter heating season. Residential and commercial customers in Oregon are allowed to opt out of the weather normalization mechanism, and as of December 31, 2022, approximately 7% of total eligible customers had opted out. NW Natural does not have a weather normalization mechanism approved for Washington customers, which account for about 12% of total customers. The decoupling and WARM mechanisms are designed to reduce, but not eliminate, the volatility of customer bills and natural gas distribution revenue. See "Regulatory Matters —*Rate Mechanisms*" above. In addition to NW Natural's local gas distribution business, the NGD segment also includes the portion of the Mist underground storage facility used to serve NGD customers, the North Mist gas storage expansion, NWN Gas Reserves, which is a wholly owned subsidiary of Energy Corp., and NW Natural RNG Holding Company, LLC.

The NGD business is primarily seasonal in nature due to higher gas usage by residential and commercial customers during the cold winter heating months. Other categories of customers experience seasonality in their usage but to a lesser extent. Seasonality affects the comparability of the results of operations of the NGD business across quarters but not across years.

NGD segment highlights include:

Dollars and therms in millions, except EPS data		2022		2021		2020
NGD net income	$	79.7	$	69.0	$	63.6
Diluted EPS - NGD segment	$	2.34	$	2.24	$	2.08
Gas sold and delivered (in therms)		1,252		1,185		1,143
NGD margin[1]	$	505.9	$	479.8	$	438.1

[1] See Natural Gas Distribution Margin Table below for additional detail.

2022 COMPARED TO 2021. NGD net income was $79.7 million in 2022 compared to $69.0 million in 2021. The primary factors contributing to the increase in NGD net income were as follows:
- $26.1 million increase in NGD margin primarily due to:
  - $14.9 million increase due to new customer rates from the 2022 Oregon and 2021 Washington rate cases that went into effect November 1, 2022;
  - $6.1 million increase driven by customer growth;
  - $3.0 million increase due to higher usage from colder comparative weather from customers that are not decoupled, net of the loss from the Oregon gas cost incentive sharing mechanism;
  - $2.9 million increase due to the amortization of deferred balances primarily related to COVID-19, cybersecurity, and ERP upgrades; and
- $12.1 million increase in other income, net primarily due to lower pension non-service costs and interest income from the equity portion of AFUDC; partially offset by
- $16.7 million increase in NGD operations and maintenance expenses due to higher contract labor, amortization expense related to cloud computing arrangements, professional service fees, and information technology costs;
- $3.4 million increase in interest expense primarily due to higher long-term debt balances and higher interest rates, partially offset by higher AFUDC debt interest income;
- $2.9 million higher income tax expense reflecting higher pretax income; and
- $2.4 million increase in depreciation expense as we continue to invest in our natural gas utility system and facilities.

Total natural gas sold and delivered in 2022 increased 6% over 2021 primarily due to 1% colder than average weather in 2022 compared to 12% warmer than average weather in 2021.

2021 COMPARED TO 2020. NGD net income was $69.0 million in 2021 compared to $63.6 million in 2020. The primary factors contributing to the increase in NGD net income were as follows:
- $41.7 million increase in NGD margin primarily due to:
  - $36.4 million increase due to new customer rates primarily from the 2020 Oregon rate case that went into effect November 1, 2020;
  - $5.7 million increase from residential customer growth and an increase in industrial customer volumes; partially offset by
  - $3.6 million decrease primarily driven by a loss from the gas cost incentive sharing mechanism in Oregon.

In addition to the increase in margin, NGD net income for 2021 reflects:
- $19.3 million increase in other NGD operating and maintenance expenses primarily due to higher information technology expenses, compensation and benefits costs, and lease expense;
- $8.9 million increase in depreciation expense due to NGD plant additions as we continued to invest in our gas utility system;
- $5.3 million higher income tax expense reflecting higher pretax income and Oregon CAT; and
- $3.3 million increase in general taxes due primarily to higher assessed property values; partially offset by
- $2.7 million increase in other income (expense), net primarily due to higher interest income on regulatory assets.

Total natural gas sold and delivered in 2021 increased 4% over 2020 primarily due to the recovery of commercial customer activity as pandemic restrictions lifted compared to the prior period and NGD meter growth.

NATURAL GAS DISTRIBUTION MARGIN TABLE. The following table summarizes the composition of NGD gas volumes, revenues, and cost of sales:

				Favorable (Unfavorable)	
In thousands, except degree day and customer data	2022	2021	2020	2022 vs. 2021	2021 vs. 2020
NGD volumes (therms):					
Residential and commercial sales	766,592	703,054	677,271	63,538	25,783
Industrial sales and transportation	485,745	481,721	465,626	4,024	16,095
Total NGD volumes sold and delivered	1,252,337	1,184,775	1,142,897	67,562	41,878
Operating revenues:					
Residential and commercial sales	$ 881,370	$ 730,794	$ 661,346	$ 150,576	$ 69,448
Industrial sales and transportation	86,810	65,299	58,678	21,511	6,621
Other distribution revenues	1,944	1,707	1,926	237	(219)
Other regulated services	19,628	19,087	19,122	541	(35)
Total operating revenues	989,752	816,887	741,072	172,865	75,815
Less: Cost of gas	429,861	292,538	262,980	(137,323)	(29,558)
Less: Environmental remediation expense	12,389	9,938	9,691	(2,451)	(247)
Less: Revenue taxes	41,627	34,600	30,291	(7,027)	(4,309)
NGD margin	$ 505,875	$ 479,811	$ 438,110	$ 26,064	$ 41,701
NGD margin[(1)]					
Residential and commercial sales	$ 455,686	$ 430,295	$ 385,989	$ 25,391	$ 44,306
Industrial sales and transportation	33,543	32,182	30,800	1,361	1,382
Gain (loss) from gas cost incentive sharing	(4,917)	(3,381)	267	(1,536)	(3,648)
Other margin	1,943	1,633	1,938	310	(305)
Other regulated services	19,620	19,082	19,116	538	(34)
NGD margin	$ 505,875	$ 479,811	$ 438,110	$ 26,064	$ 41,701
Degree days[(2)]					
Average[(3)]	2,686	2,692	2,706	(6)	(14)
Actual	2,712	2,378	2,384	14 %	— %
Percent colder (warmer) than average weather	1 %	(12)%	(12)%		
NGD meters - end of period:					
Residential meters	724,287	715,958	704,675	8,329	11,283
Commercial meters	69,139	68,961	68,812	178	149
Industrial meters	1,071	978	989	93	(11)
Total number of meters	794,497	785,897	774,476	8,600	11,421
NGD meter growth:					
Residential meters	1.2 %	1.6 %			
Commercial meters	0.3 %	0.2 %			
Industrial meters	9.5 %	(1.1)%			
Total meter growth	1.1 %	1.5 %			

(1) Amounts reported as NGD margin for each category of meters are operating revenues less cost of gas, environmental remediation expense and revenue taxes.

(2) Heating degree days are units of measure reflecting temperature-sensitive consumption of natural gas, calculated by subtracting the average of a day's high and low temperatures from 59 degrees Fahrenheit.

(3) Average weather represents the 25-year average of heating degree days. Beginning November 1, 2022, average weather is calculated over the period June 1, 1996 through May 31, 2021, as determined in NW Natural's 2022 Oregon general rate case. From November 1, 2020 through October 31, 2022, average weather was calculated over the period June 1, 1994 through May 31, 2019, as determined in NW Natural’s 2020 Oregon general rate case.

Residential and Commercial Sales

The primary factors that impact results of operations in the residential and commercial markets are customer growth, seasonal weather patterns, energy prices, competition from other energy sources, and economic conditions in our service areas. The impact of weather on margin is significantly reduced through NW Natural's weather normalization mechanism in Oregon; approximately 81% of NW Natural's total customers are covered under this mechanism. The remaining customers either opt out of the mechanism or are located in Washington, which does not have a similar mechanism in place. For more information on the weather mechanism, see "Regulatory Matters—Rate Mechanisms—*WARM*" above.

NGD residential and commercial sales highlights include:

In millions	2022	2021	2020
Volumes (therms):			
Residential sales	478.1	445.6	435.2
Commercial sales	288.5	257.5	242.1
Total volumes	766.6	703.1	677.3
Operating revenues:			
Residential sales	$ 595.0	$ 506.2	$ 460.3
Commercial sales	286.4	224.6	201.0
Total operating revenues	$ 881.4	$ 730.8	$ 661.3
NGD Margin:			
Residential margin	$ 328.2	$ 312.5	$ 281.1
Commercial margin	127.5	117.8	104.9
Total NGD margin	$ 455.7	$ 430.3	$ 386.0

2022 COMPARED TO 2021. The increase of $150.6 million in total NGD residential and commercial operating revenue and $25.4 million in NGD margin were primarily the result of new customer rates in Oregon and Washington that took effect on November 1, 2022, 1.2% growth in residential customer meters, and higher usage from colder comparative weather from customers that are not decoupled. Sales volumes increased 63.5 million therms, or 9%, primarily due to higher usage driven by comparatively colder weather.

2021 COMPARED TO 2020. The increase of $69.5 million in total residential and commercial operating revenue and $44.3 million in NGD margin were primarily the result of new customer rates in Oregon that took effect on November 1, 2020, growth in residential customer meters, and higher commercial volumes as COVID-19 restrictions and closures were lifted. Sales volumes increased 25.8 million therms, or 4%, primarily due to growth in residential customer meters and higher commercial volumes as COVID-19 restrictions and closures were lifted.

Industrial Sales and Transportation

Industrial customers have the option of purchasing sales or transportation services. Under the sales service, the customer buys the gas commodity from NW Natural. Under the transportation service, the customer buys the gas commodity directly from a third-party gas marketer or supplier. The NGD gas commodity cost is primarily a pass-through cost to customers; therefore, NGD profit margins are not materially affected by an industrial customer's decision to purchase gas from third parties. Industrial and large commercial customers may also select between firm and interruptible service options, with firm services generally providing higher profit margins compared to interruptible services. To help manage gas supplies, industrial tariffs are designed to provide some certainty regarding industrial customers' volumes by requiring an annual service election which becomes effective November 1, special charges for changes between elections, and in some cases, a minimum or maximum volume requirement before changing options.

NGD industrial sales and transportation highlights include:

In millions	2022	2021	2020
Volumes (therms):			
Firm and interruptible sales	104.4	90.8	82.9
Firm and interruptible transportation	381.3	390.9	382.7
Total volumes	485.7	481.7	465.6
NGD Margin:			
Firm and interruptible sales	$ 13.6	$ 12.6	$ 11.6
Firm and interruptible transportation	19.9	19.6	19.2
Total NGD margin	$ 33.5	$ 32.2	$ 30.8

2022 COMPARED TO 2021. NGD total industrial sales and transportation volumes increased 4.0 million therms, or 1%, primarily due to higher usage from multiple customers, most notably in the light manufacturing, primary metals, and electric manufacturing industries, partially offset by lower usage from customers in the plastic manufacturing industry. NGD margin increased $1.3 million primarily driven by new rates in Oregon and Washington that took effect on November 1, 2022.

2021 COMPARED TO 2020. NGD total industrial sales and transportation volumes increased 16.1 million therms, or 3%, primarily due to higher usage from multiple customers, most notably in the pulp and paper and chemical manufacturing industries. NGD margin increased $1.4 million primarily driven by new rates in Oregon that took effect on November 1, 2020.

Other Regulated Services Margin

Other Regulated Services primarily consist of lease revenues from NW Natural's North Mist storage facility as well as other lease revenues for compressed natural gas assets.

Other regulated services margin highlights include:

In millions		2022		2021		2020
North Mist storage services	$	19.4	$	18.9	$	19.5
Other services		0.2		0.2		(0.4)
Total other regulated services	$	19.6	$	19.1	$	19.1

2022 COMPARED TO 2021. Other regulated services margin increased $0.5 million due to an increase in storage service revenue from the North Mist facility. See Note 7 for more information regarding North Mist expansion lease accounting.

2021 COMPARED TO 2020. Other regulated services margin was relatively flat when compared to the prior period. The North Mist facility did not experience any significant fluctuations in storage service revenue. See Note 7 for more information regarding North Mist expansion lease accounting.

Cost of Gas

Cost of gas as reported by the NGD segment includes gas purchases, gas withdrawn from storage inventory, gains and losses from commodity hedges, pipeline demand costs, seasonal demand cost balancing adjustments, renewable natural gas and its attributes, including renewable thermal certificates, regulatory gas cost deferrals, gas reserves costs, and company gas use. The OPUC and WUTC generally require natural gas commodity costs to be billed to customers at the actual cost incurred, or expected to be incurred. Customer rates are set each year so that if cost estimates were met the NGD business would not earn a profit or incur a loss on gas commodity purchases; however, in Oregon we have the incentive sharing mechanism described under "Regulatory Matters—Rate Mechanisms—*Purchased Gas Adjustment*" above. In addition to the PGA incentive sharing mechanism, gains and losses from hedge contracts entered into after annual PGA rates are effective for Oregon customers are also required to be shared and therefore may impact net income. Further, NW Natural also has a regulatory agreement whereby it earns a rate of return on its investment in the gas reserves acquired under the original agreement with Encana and includes gas from the amended gas reserves agreement at a fixed rate of $0.4725 per therm, which are also reflected in NGD margin. See "Application of Critical Accounting Policies and Estimates—*Derivative Instruments and Hedging Activities*" below.

Cost of gas highlights include:

In millions, except where indicated		2022		2021		2020
Cost of gas	$	429.9	$	292.5	$	263.0
Volumes sold (therms)[1]		871.0		793.9		760.2
Average cost of gas (cents per therm)	$	0.49	$	0.37	$	0.35
Gain (loss) from gas cost incentive sharing	$	(4.9)	$	(3.4)	$	0.3

[1] This calculation excludes volumes delivered to industrial transportation customers.

2022 COMPARED TO 2021. Cost of gas increased $137.4 million, or 47%, primarily due to a 32% increase in the average cost of gas with the majority of these higher gas costs embedded in the PGA. The remaining increase in cost of gas is primarily the result of a 10% increase in volumes sold, driven by customer growth and comparatively colder weather. For a discussion of the gas cost incentive sharing mechanism, see "Regulatory Matters—Rate Mechanisms—*Purchased Gas Adjustment*" above.

2021 COMPARED TO 2020. Cost of gas increased $29.5 million, or 11%, primarily due to a $3.4 million loss from gas cost incentive sharing driven by costs related to the 2021 cold weather event that were not deferred for future recovery. The remaining increase in cost of gas is primarily the result of a 4% increase in volumes sold driven by customer growth and higher commercial volumes as COVID-19 restrictions and closures were lifted. For a discussion of the gas cost incentive sharing mechanism, see "Regulatory Matters—Rate Mechanisms—*Purchased Gas Adjustment*" above.

Other

Other activities aggregated and reported as other at NW Holdings include NNG Financial's investment in Kelso-Beaver Pipeline (KB Pipeline); NW Natural Renewables Holdings, LLC and its non-regulated renewable natural gas activities; NWN Water, which owns and continues to pursue investments in the water and wastewater sector; and NWN Water's investment in Avion Water Company, Inc. (Avion Water). Other activities aggregated and reported as other at NW Natural include the non-NGD storage activity at Mist as well as asset management services and the appliance retail center operations. See Note 4 for further discussion of our business segment and other, as well as our direct and indirect wholly-owned subsidiaries. See Note 13 for information on our Avion Water investment.

On August 6, 2020, NWN Energy completed the sale of its interest in Trail West Holdings, LLC (TWH) to an unrelated third party. See Note 13 for further details.

At Mist, NW Natural provides gas storage services to customers in the interstate and intrastate markets using storage capacity that has been developed in advance of NGD customers' requirements. Pre-tax income from gas storage at Mist and asset management services is subject to revenue sharing with NGD customers. Under this regulatory incentive sharing mechanism, NW Natural retains 80% of pre-tax income from Mist gas storage services and asset management services when the underlying costs of the capacity being used are not included in NGD business rates. The remaining 20% is credited to a deferred regulatory account for credit to NGD customers. To the extent that the capacity used is included in NGD rates, NW Natural retains 10% of pre-tax income from such storage and asset management services and 90% is credited to NGD business customers.

The following table presents the results of activities aggregated and reported as other for both NW Holdings and NW Natural:

In millions, except EPS data		2022		2021		2020
NW Natural other - net income	$	11.9	$	12.2	$	7.0
Other NW Holdings activity		(5.3)		(2.5)		(0.3)
NW Holdings other - net income	$	6.6	$	9.7	$	6.7
Diluted EPS - NW Holdings - other	$	0.20	$	0.32	$	0.22

2022 COMPARED TO 2021. Other net income decreased $3.1 million and $0.3 million at NW Holdings and NW Natural, respectively. The decrease at NW Holdings was driven by the decrease at NW Natural, higher interest expense at the holding company, and costs associated with non-regulated renewable natural gas activities.

2021 COMPARED TO 2020. Other net income increased $3.0 million and $5.2 million at NW Holdings and NW Natural, respectively. The increase at NW Natural was primarily due to $7.9 million of higher asset management revenue primarily related to the 2021 cold weather event, partially offset by $2.1 million of income tax expense associated with the higher revenue. The increase at NW Holdings was driven by the increase at NW Natural, partially offset by higher business development and consulting costs at the holding company.

Consolidated Operations

Operations and Maintenance

Operations and maintenance highlights include:

In millions		2022		2021		2020
NW Natural	$	204.8	$	188.8	$	168.9
Other NW Holdings operations and maintenance		19.9		15.4		11.2
NW Holdings	$	224.7	$	204.2	$	180.1

2022 COMPARED TO 2021. Operations and maintenance expense increased $16.0 million for NW Natural primarily due to the following:
- $6.0 million increase in contract labor for safety and reliability and contracted support for information technology system upgrades;
- $4.1 million increase in amortization expense related to cloud computing arrangements;
- $3.0 million increase in information technology maintenance and support; and
- $2.0 million increase in professional service fees.

Operations and maintenance expense increased $20.5 million for NW Holdings primarily due to the following:
- $16.0 million increase in operations and maintenance expense at NW Natural as discussed above; and
- $4.5 million increase in other NW Holdings operations and maintenance expense primarily due to costs associated with water and wastewater subsidiaries and non-regulated renewable natural gas activities.

2021 COMPARED TO 2020. Operations and maintenance expense increased $19.9 million for NW Natural primarily due to the following:
- $7.4 million increase in contractor, professional service fees and license costs related to information technology system upgrades;
- $4.8 million increase related to higher compensation and benefit costs; and
- $3.6 million increase in lease expense related to a new headquarters and operations center.

Operations and maintenance expense increased $24.1 million for NW Holdings primarily due to the following:

- $19.9 million increase in operations and maintenance expense at NW Natural as discussed above; and
- $4.2 million increase in other NW Holdings operations and maintenance expense primarily due to higher business development and consulting costs at the holding company.

Depreciation

Depreciation highlights include:

In millions	2022	2021	2020
NW Natural	$ 113.0	$ 110.5	$ 101.6
Other NW Holdings depreciation	3.7	3.0	2.1
NW Holdings	$ 116.7	$ 113.5	$ 103.7

2022 COMPARED TO 2021. Depreciation expense increased $2.5 million for NW Natural, primarily due to additional capital investments in the distribution system, Mist storage, and information technology systems, as well as renovation and construction of resource and operations service centers. The increase was partially offset by the amortization of cloud computing arrangements, which are recorded within operations and maintenance expenses beginning in 2022.

Depreciation expense increased $3.2 million for NW Holdings, primarily due to a $0.7 million increase in other NW Holdings depreciation related to water and wastewater subsidiaries and a $2.5 million increase at NW Natural as discussed above.

2021 COMPARED TO 2020. Depreciation expense increased $8.9 million for NW Natural, primarily due to additional capital investments in the distribution system, Mist storage, and information technology systems, as well as renovation and construction of resource and operations service centers.

Depreciation expense increased $9.8 million for NW Holdings, primarily due to a $0.9 million increase in other NW Holdings depreciation related to water and wastewater acquisitions and an $8.9 million increase at NW Natural as discussed above.

Other Income (Expense), Net

Other income (expense), net highlights include:

In millions	2022	2021	2020
NW Natural total other income (expense), net	$ (0.4)	$ (12.7)	$ (15.1)
Other NW Holdings activity	1.6	0.1	1.2
NW Holdings total other income (expense), net	$ 1.2	$ (12.6)	$ (13.9)

2022 COMPARED TO 2021. Other expense, net decreased $12.3 million at NW Natural primarily due to lower pension non-service costs and interest income from the equity portion of AFUDC. Costs related to our defined benefit pension plan in 2022 decreased compared to the prior year due to changes in assumptions and gains on plan assets.

Other income, net increased $13.8 million at NW Holdings driven by the change at NW Natural discussed above, in addition to earnings from Avion Water. Other income (expense), net primarily consists of regulatory interest, pension and other postretirement non-service costs, gains from company-owned life insurance, and donations.

2021 COMPARED TO 2020. Other income (expense), net changed $2.4 million at NW Natural primarily due to higher interest income on regulatory assets and lower pension non-service costs. Other income (expense), net changed $1.3 million at NW Holdings driven by the change at NW Natural discussed above, partially offset by a gain recognized in the prior period related to the sale of Trail West.

Interest Expense, Net

Interest expense, net highlights include:

In millions	2022	2021	2020
NW Natural	$ 46.3	$ 43.0	$ 40.9
Other NW Holdings interest expense	6.9	1.5	2.2
NW Holdings	$ 53.2	$ 44.5	$ 43.1

2022 COMPARED TO 2021. Interest expense, net, increased $3.3 million at NW Natural primarily due to a higher interest rate on a lower commercial paper balance and higher interest rates and a higher level of long-term debt, partially offset by higher AFUDC debt interest income.

Interest expense, net, increased $8.7 million at NW Holdings primarily due to the increase at NW Natural discussed above and higher interest expense on the credit facility and long-term debt at NW Holdings as a result of higher balances and higher interest rates.

2021 COMPARED TO 2020. Interest expense, net, increased $2.1 million at NW Natural primarily due to lower AFUDC debt interest income and higher interest on long-term debt.

Interest expense, net, increased $1.4 million at NW Holdings primarily due to the increase at NW Natural discussed above, partially offset by lower interest expense on the credit agreement at NW Holdings.

Income Tax Expense

NW Holdings income tax expense highlights include:

In millions	2022	2021	2020
Income tax expense	$ 29.1	$ 27.4	$ 21.1
Effective tax rate	25.2 %	25.8 %	23.1 %

NW Natural income tax expense highlights include:

In millions	2022	2021	2020
Income tax expense	$ 31.0	$ 28.3	$ 21.1
Effective tax rate	25.3 %	25.9 %	23.0 %

2022 COMPARED TO 2021. The effective tax rate decreased 0.6 percentage points at both NW Holdings and NW Natural. The decrease in the effective tax rate is primarily due to lower income tax amortization of the 2020 Oregon Corporate Activity Tax (CAT) in 2022, which was subject to regulatory deferral when it became effective on January 1, 2020 and then amortized in income tax expense as recovery began in late 2020, 2021, and 2022.

2021 COMPARED TO 2020. The effective tax rate increased 2.7 and 2.9 percentage points at NW Holdings and NW Natural, respectively. The increase in the effective tax rate is primarily due to Oregon Corporate Activity Tax, the majority of which is incurred because of Oregon regulated operations and for which rate recovery began on November 1, 2020.

Discontinued Operations

On June 20, 2018, NWN Gas Storage, a wholly-owned subsidiary of NW Holdings, entered into a Purchase and Sale Agreement (the Agreement) that provided for the sale by NWN Gas Storage of all of its membership interests in Gill Ranch. Gill Ranch owns a 75% interest in the natural gas storage facility located near Fresno, California known as the Gill Ranch Gas Storage Facility.

On December 4, 2020, NWN Gas Storage closed the sale of all the memberships interests in Gill Ranch and received payment of the initial cash purchase price of $13.5 million less the $1.0 million deposit previously paid. Furthermore, additional payments to NWN Gas Storage may be made subject to a maximum amount of $15.0 million in the aggregate (subject to a working capital adjustment) based on the economic performance of Gill Ranch each full gas storage year (April 1 of one year through March 31 of the following year) occurring after the closing and the remaining portion of the 2020-2021 gas storage year and will continue until such time as the maximum amount has been paid. The fair value of this arrangement at the closing date was zero based on a discounted cash flow forecast. Subsequent changes in the fair value will be recorded in earnings. The completion of the sale resulted in an after-tax gain of $5.9 million for the year ended December 31, 2020.

The results of Gill Ranch Storage have been determined to be discontinued operations until the date of sale and are presented separately, net of tax, from the results of continuing operations of NW Holdings for all periods presented. See Note 18 for more information on the Agreement and the results of our discontinued operations.

FINANCIAL CONDITION

Capital Structure

NW Holdings' long-term goal is to maintain a strong and balanced consolidated capital structure. NW Natural targets a regulatory capital structure of 50% common equity and 50% long-term debt, which is consistent with approved regulatory allocations in Oregon, which has an allocation of 50% common equity and 50% long-term debt without recognition of short-term debt, and Washington, which has an allocation of 50% long-term debt, 1% short-term debt, and 49% common equity.

When additional capital is required, debt or equity securities are issued depending on both the target capital structure and market conditions. These sources of capital are also used to fund long-term debt retirements and short-term commercial paper maturities. See "*Liquidity and Capital Resources*" below and Note 9. Achieving our target capital structure and maintaining sufficient liquidity to meet operating requirements is necessary to maintain attractive credit ratings and provide access to the capital markets at reasonable costs.

NW Holdings' consolidated capital structure, excluding short-term debt, was as follows:

	December 31,	
	2022	2021
Common equity	46.8 %	47.2 %
Long-term debt (including current maturities)	53.2	52.8
Total	100.0 %	100.0 %

NW Natural's consolidated capital structure, excluding short-term debt, was as follows:

	December 31,	
	2022	2021
Common equity	51.4 %	49.8 %
Long-term debt (including current maturities)	48.6	50.2
Total	100.0 %	100.0 %

As of December 31, 2022 and 2021, NW Holdings' consolidated capital structure included common equity of 42.4% and 39.5%, long-term debt of 45.0% and 44.0%, and short-term debt including current maturities of long-term debt of 12.6% and 16.5%, respectively. As of December 31, 2022 and 2021, NW Natural's consolidated capital structure included common equity of 47.9% and 44.2%, long-term debt of 41.6% and 44.7%, and short-term debt including current maturities of long-term debt of 10.5% and 11.1%, respectively.

During 2022, NW Natural's capital structure changed primarily due to the issuance of long-term debt and capital contributions from NW Holdings. NW Holdings' capital structure changed primarily due to the issuance of long-term debt and common stock at NW Holdings. See further discussion below in "Cash Flows — *Financing Activities*".

Liquidity and Capital Resources

At December 31, 2022 and December 31, 2021, NW Holdings had approximately $29.3 million and $18.6 million, and NW Natural had approximately $13.0 million and $12.3 million, of cash and cash equivalents, respectively. In order to maintain sufficient liquidity during periods when capital markets are volatile, NW Holdings and NW Natural may elect to maintain higher cash balances and add short-term borrowing capacity. NW Holdings and NW Natural may also pre-fund their respective capital expenditures when long-term fixed rate environments are attractive. NW Holdings and NW Natural expect to have ample liquidity in the form of cash on hand and from operations and available credit capacity under credit facilities to support funding needs.

Equity Issuance

On April 1, 2022, NW Holdings issued and sold 2,875,000 shares of its common stock pursuant to a registration statement on Form S-3 and related prospectus supplement. NW Holdings received net offering proceeds, after deducting the underwriter's discounts and commissions and estimated expenses payable by NW Holdings of approximately $138.6 million.

ATM Equity Program

In August 2021, NW Holdings initiated an at-the-market (ATM) equity program by entering into an equity distribution agreement under which NW Holdings may issue and sell from time to time shares of common stock, no par value, having an aggregate gross sales price of up to $200 million. NW Holdings is under no obligation to offer and sell common stock under the ATM equity program, which expires in August 2024. Any shares of common stock offered under the ATM equity program are registered on NW Holdings' universal shelf registration statement filed with the SEC. During the year ended December 31, 2022, NW Holdings issued and sold 1,381,728 shares of common stock pursuant to the ATM equity program resulting in cash proceeds of $69.7 million, net of fees and commissions paid to agents of $1.4 million. As of December 31, 2022, NW Holdings had $111.1 million of equity available for issuance under the program.

NW Holdings

For NW Holdings, short-term liquidity is primarily provided by cash balances, dividends from its operating subsidiaries, in particular NW Natural, available cash from a multi-year credit facility, and short-term credit facilities. NW Holdings also has a universal shelf registration statement filed with the SEC for the issuance of debt and equity securities. NW Holdings long-term debt, if any, and equity issuances are primarily used to provide equity contributions to NW Holdings' operating subsidiaries for operating and capital expenditures and other corporate purposes. From 2023 through 2025, we estimate NW Holdings' and NW Natural's combined incremental capital needs to be in the range of $450 million to $550 million. NW Holdings intends to use raised capital to support NW Natural, NW Natural Water, and NW Natural Renewables operating and capital expenditure programs. NW Holdings' issuance of securities is not subject to regulation by state public utility commissions, but the dividends from NW Natural to NW Holdings are subject to regulatory ring-fencing provisions. NW Holdings guarantees the debt of its wholly-owned subsidiary, NWN Water. See "*Long-Term Debt*" below for more information regarding NWN Water debt.

As part of the ring-fencing conditions agreed upon with the OPUC and WUTC, NW Natural may not pay dividends or make distributions to NW Holdings if NW Natural's credit ratings and common equity ratio, defined as the ratio of equity to long-term debt, fall below specified levels. If NW Natural's long-term secured credit ratings are below A- for S&P and A3 for Moody's, dividends may be issued so long as NW Natural's common equity ratio is 45% or more. If NW Natural's long term secured credit ratings are below BBB for S&P and Baa2 for Moody's, dividends may be issued so long as NW Natural's common equity ratio is 46% or more. Dividends may not be issued if NW Natural's long-term secured credit ratings are BB+ or below for S&P or Ba1 or below for Moody's, or if NW Natural's common equity ratio is below 44%, where the ratio is measured using common equity and long-term debt excluding imputed debt or debt-like lease obligations. In each case, common equity ratios are determined based on a preceding or projected 13-month average. In addition, there are certain OPUC notice requirements for dividends in excess of 5% of NW Natural's retained earnings.

Additionally, if NW Natural's common equity (excluding goodwill and equity associated with non-regulated assets), on a preceding or projected 13-month average basis, is less than 46% of NW Natural's capital structure, NW Natural is required to notify the OPUC, and if the common equity ratio falls below 44%, file a plan with the OPUC to restore its equity ratio to 44%. This condition is designed to ensure NW Natural continues to be adequately capitalized under the holding company structure. Under the WUTC order, the average common equity ratio must not exceed 56%.

At December 31, 2022 and 2021, NW Natural satisfied the ring-fencing provisions described above.

Based on several factors, including current cash reserves, committed credit facilities, its ability to receive dividends from its operating subsidiaries, in particular NW Natural, and an expected ability to issue long-term debt and equity securities in the capital markets, NW Holdings believes its liquidity is sufficient to meet anticipated near-term cash requirements, including all contractual obligations, investing, and financing activities as discussed in "*Cash Flows*" below.

NW HOLDINGS DIVIDENDS. Quarterly dividends have been paid on common stock each year since NW Holdings' predecessor's stock was first issued to the public in 1951. Annual common stock dividend payments per share, adjusted for stock splits, have increased each year since 1956. The declarations and amount of future dividends to shareholders will depend upon earnings, cash flows, financial condition, NW Natural's ability to pay dividends to NW Holdings and other factors. The amount and timing of dividends payable on common stock is at the sole discretion of the NW Holdings Board of Directors.

NW Natural

For the NGD business segment, short-term borrowing requirements typically peak during colder winter months when the NGD business borrows money to cover the lag between natural gas purchases and bill collections from customers. Short-term liquidity for the NGD business is primarily provided by cash balances, internal cash flow from operations, proceeds from the sale of commercial paper notes, as well as available cash from multi-year credit facilities, short-term credit facilities, company-owned life insurance policies, the sale of long-term debt, and equity contributions from NW Holdings. NW Natural's long-term debt and contributions from NW Holdings are primarily used to finance NGD capital expenditures, refinance maturing debt, and provide temporary funding for other general corporate purposes of the NGD business.

Based on its current debt ratings (see "*Credit Ratings*" below), NW Natural has been able to issue commercial paper and long-term debt at attractive rates. In the event NW Natural is not able to issue new long-term debt due to adverse market conditions or other reasons, NW Natural expects that near-term liquidity needs can be met using internal cash flows, issuing commercial paper, receiving equity contributions from NW Holdings, or drawing upon a committed credit facility. NW Natural also has a universal shelf registration statement filed with the SEC for the issuance of secured and unsecured debt securities.

In the event senior unsecured long-term debt ratings are downgraded, or outstanding derivative positions exceed a certain credit threshold, counterparties under derivative contracts could require NW Natural to post cash, a letter of credit, or other forms of collateral, which could expose NW Natural to additional cash requirements and may trigger increases in short-term borrowings while in a net loss position. NW Natural was not required to post collateral at December 31, 2022. See Note 15 below.

Other items that may have a significant impact on NW Natural's liquidity and capital resources include NW Natural's pension contribution requirements and environmental expenditures.

PENSION CONTRIBUTIONS. NW Natural does not expect to make contributions to its company-sponsored defined benefit plan, which is closed to new employees, over the next several years under applicable laws and regulations. See "Application of Critical Accounting Policies—*Pensions and Postretirement Benefits*" below and Note 10 for more information.

ENVIRONMENTAL EXPENDITURES. NW Natural expects to continue using cash resources to fund environmental liabilities for future environmental remediation or action. NW Natural has authorizations in Oregon and Washington to defer costs related to remediation of properties that are owned or were previously owned by NW Natural. In Oregon, a Site Remediation and Recovery Mechanism (SRRM) is currently in place to recover prudently incurred costs allocable to Oregon customers, subject to an earnings test. On October 21, 2019 the WUTC authorized an Environmental Cost Recovery Mechanism (ECRM) for recovery of prudently incurred costs allocable to Washington customers beginning November 1, 2019. See Note 17 and "Results of Operations—Regulatory Matters—*Environmental Cost Deferral and Recovery*" above.

Based on several factors, including current credit ratings, NW Natural's commercial paper program, current cash reserves, committed credit facilities, and an expected ability to issue long-term debt and receive equity contributions from NW Holdings, NW Natural believes its liquidity is sufficient to meet anticipated near-term cash requirements, including all contractual obligations, and investing and financing activities as discussed in "*Cash Flows*" below.

NW NATURAL DIVIDENDS. The declarations and amount of future dividends to NW Holdings will depend upon earnings, cash flows, financial condition, the satisfaction of OPUC and WUTC regulatory ring-fencing restrictions, and other factors. The amount and timing of dividends payable on common stock is subject to approval of the NW Natural Board of Directors.

Gas and Pipeline Capacity Purchase Agreements

NW Natural has signed agreements providing for the reservation of firm pipeline capacity under which it is required to make fixed monthly payments for contracted capacity. The pricing component of the monthly payment is established, subject to change, by U.S. or Canadian regulatory bodies, or is established directly with private counterparties, as applicable. In addition, NW Natural has entered into long-term agreements to release firm pipeline capacity. NW Natural also enters into short-term and long-term gas purchase agreements. Refer to Note 16 for gas and pipeline capacity purchase commitments.

NW Natural Renewables is a newly formed, non-utility regulated subsidiary of NW Natural Holdings established to pursue non-regulated renewable natural gas activities. In September 2021, a subsidiary of NW Natural Renewables and a subsidiary of EDL, a global producer of sustainable distributed energy, executed agreements to develop two production facilities that are designed to convert landfill waste gases to renewable natural gas (RNG). Testing and commissioning of the production facilities is expected to occur in the spring of 2023. Upon completion of each facility, the subsidiary of NW Natural Renewables is committed to make cash payments totaling $50.1 million to partially fund the infrastructure required to condition biogas and connect gas production to existing regional pipeline networks. Alongside these development agreements, a subsidiary of NW Natural Renewables and a subsidiary of EDL executed agreements designed to secure a 20-year supply of RNG for NW Natural Renewables. Following the completion of each facility, we estimate the amount of RNG purchases based on prices and quantities specified in the agreements are as follows: approximately $6.6 million in 2023, $10.5 million in 2024, $21.0 million in 2025, $21.0 million in 2026, $27.3 million in 2027 and $567.8 million thereafter.

Other Purchase Agreements

Other purchase commitments primarily consist of remaining balances under existing purchase orders and gas storage agreements. At December 31, 2022, the amount due over the duration of the purchase agreements totaled $41.1 million. Except for these certain purchase commitments, NW Holdings and NW Natural have no material off-balance sheet financing arrangements.

Short-Term Debt

The primary source of short-term liquidity for NW Holdings is cash balances, dividends from its operating subsidiaries, in particular NW Natural, available cash from a multi-year credit facility, and short-term credit facilities it may enter into from time to time.

The primary source of short-term liquidity for NW Natural is from the sale of commercial paper, available cash from a multi-year credit facility, and short-term credit facilities it may enter into from time to time. In addition to issuing commercial paper or entering into bank loans to meet working capital requirements, including seasonal requirements to finance gas purchases and accounts receivable, short-term debt may also be used to temporarily fund capital requirements. For NW Natural, commercial paper and bank loans are periodically refinanced through the sale of long-term debt or equity contributions from NW Holdings. Commercial paper, when outstanding, is sold through two commercial banks under an issuing and paying agency agreement and is supported by one or more unsecured revolving credit facilities. See “Credit Agreements” below.

At December 31, 2022 and 2021, NW Natural's short-term debt consisted of the following:

	December 31, 2022		December 31, 2021	
In millions	Balance Outstanding	Weighted Average Interest Rate[1]	Balance Outstanding	Weighted Average Interest Rate[1]
NW Natural:				
Commercial paper	$ 170.2	4.6 %	$ 245.5	0.3 %
Other (NW Holdings):				
Credit agreement	88.0	5.3 %	144.0	1.1 %
NW Holdings	$ 258.2		$ 389.5	

[1] Weighted average interest rate on outstanding short-term debt

Credit Agreements

NW Holdings

NW Holdings has a $200 million sustainability-linked credit agreement, with a feature that allows it to request increases in the total commitment amount, up to a maximum of $300 million. The maturity date of the agreement is November 3, 2026, with available extensions of commitments for two additional one-year periods, subject to lender approval.

All lenders under the NW Holdings credit agreement are major financial institutions with committed balances and investment grade credit ratings as of December 31, 2022 as follows:

In millions

Lender rating, by category	Loan Commitment
AA/Aa	$ 200
Total	$ 200

Based on credit market conditions, it is possible one or more lending commitments could be unavailable to NW Holdings if the lender defaulted due to lack of funds or insolvency; however, NW Holdings does not believe this risk to be imminent due to the lenders' strong investment-grade credit ratings. There was $88.0 million and $144.0 million of outstanding balances under the NW Holdings agreement at December 31, 2022 and 2021, respectively.

The NW Holdings credit agreement permits the issuance of letters of credit in an aggregate amount of up to $40 million. The principal amount of borrowings under the credit agreement is due and payable on the maturity date. The credit agreement requires NW Holdings to maintain a consolidated indebtedness to total capitalization ratio of 70% or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. NW Holdings was in compliance with this covenant at December 31, 2022 and 2021, with consolidated indebtedness to total capitalization ratios of 57.6% and 60.5%, respectively.

The NW Holdings credit agreement also requires NW Holdings to maintain debt ratings (which are defined by a formula using NW Natural's credit ratings in the event NW Holdings does not have a credit rating) with Standard & Poor's (S&P) and Moody's Investors Service, Inc. (Moody’s) and notify the lenders of any change in its senior unsecured debt ratings or senior secured debt ratings, as applicable, by such rating agencies. A change in NW Holdings' debt ratings by S&P or Moody’s is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit agreement. Rather, interest rates on any loans outstanding under the credit agreements are tied to debt ratings and therefore, a change in the debt rating would increase or decrease the cost of any loans under the credit agreements when ratings are changed. NW Holdings does not currently maintain ratings with S&P or Moody's.

Interest charges on the NW Holdings credit agreement were indexed to the London Interbank Offered Rate (LIBOR) through January 31, 2023. The agreement was amended to replace LIBOR with the secured overnight financing rate (SOFR) beginning February 2023. The SOFR is subject to a 10 basis point spread adjustment. The NW Holdings credit agreement also includes a mechanism that can increase or decrease the undrawn interest rate by up to 1 basis point and undrawn interest rate by up to 5 basis points in accordance with NW Holdings’ independently verified achievement of quantifiable metrics related to two goals—one related to carbon savings and one related to in-line inspections of NW Natural’s transmission pipeline. Performance against these metrics is designed to be assessed annually with pricing adjustments, if any, resetting off of primary pricing annually and not cumulatively.

NW Holdings had no letters of credit issued and outstanding at December 31, 2022 and 2021.

NW Natural

NW Natural has a sustainability-linked multi-year credit agreement for unsecured revolving loans totaling $400 million, with a feature that allows NW Natural to request increases in the total commitment amount, up to a maximum of $600 million. The maturity date of the agreement is November 3, 2026 with an available extension of commitments for two additional one-year periods, subject to lender approval.

All lenders under the NW Natural credit agreement are major financial institutions with committed balances and investment grade credit ratings as of December 31, 2022 as follows:

In millions

Lender rating, by category	Loan Commitment
AA/Aa	$ 400
Total	$ 400

Based on credit market conditions, it is possible one or more lending commitments could be unavailable to NW Natural if the lender defaulted due to lack of funds or insolvency; however, NW Natural does not believe this risk to be imminent due to the lenders' strong investment-grade credit ratings.

The NW Natural credit agreement permits the issuance of letters of credit in an aggregate amount of up to $60 million. The principal amount of borrowings under the credit agreement is due and payable on the maturity date. There were no outstanding balances under this credit agreement at December 31, 2022 or 2021. The credit agreement requires NW Natural to maintain a consolidated indebtedness to total capitalization ratio of 70% or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. NW Natural was in compliance with this covenant at December 31, 2022 and 2021, with consolidated indebtedness to total capitalization ratios of 52.1% and 55.8%, respectively.

The NW Natural credit agreement also requires NW Natural to maintain credit ratings with S&P and Moody's and notify the lenders of any change in NW Natural's senior unsecured debt ratings or senior secured debt ratings, as applicable, by such rating agencies. A change in NW Natural's debt ratings by S&P or Moody's is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit agreement. Rather, interest rates on any loans outstanding under the credit agreement are tied to debt ratings and therefore, a change in the debt rating would increase or decrease the cost of any loans under the credit agreement when ratings are changed. See "*Credit Ratings*" below.

Interest charges on the NW Natural credit agreement were indexed to the LIBOR through January 31, 2023. The agreement was amended to replace LIBOR with the SOFR beginning February 2023. The SOFR is subject to a 10 basis point spread adjustment. The NW Natural credit agreement also includes a mechanism that can increase or decrease the undrawn interest rate by up to 1 basis point and undrawn interest rate by up to 5 basis points in accordance with NW Natural's independently verified achievement of quantifiable metrics related to two goals—one related to carbon savings and one related to in-line inspections of NW Natural's transmission pipeline. Performance against these metrics is designed to be assessed annually with pricing adjustments, if any, resetting off of primary pricing annually and not cumulatively.

In February 2023, NW Natural issued a $14 million letter of credit through its existing credit agreement. There were no other letters of credit outstanding under the credit agreement.

Credit Ratings

NW Holdings does not currently maintain ratings with S&P or Moody's. NW Natural's credit ratings are a factor of liquidity, potentially affecting access to the capital markets including the commercial paper market. NW Natural's credit ratings also have an impact on the cost of funds and the need to post collateral under derivative contracts.

The following table summarizes NW Natural's current credit ratings:

	S&P	Moody's
Commercial paper (short-term debt)	A-1	P-2
Senior secured (long-term debt)	AA-	A2
Senior unsecured (long-term debt)	n/a	Baa1
Corporate credit rating	A+	n/a
Ratings outlook	Stable	Stable

The above credit ratings and ratings outlook are dependent upon a number of factors, both qualitative and quantitative, and are subject to change at any time. The disclosure of or reference to these credit ratings is not a recommendation to buy, sell or hold NW Holdings or NW Natural securities. Each rating should be evaluated independently of any other rating.

As part of the ring-fencing conditions agreed upon with the OPUC and WUTC, NW Holdings and NW Natural are required to maintain separate credit ratings, long-term debt ratings, and preferred stock ratings, if any.

Long-Term Debt

Issuance of Long-Term Debt

In December 2022, NW Natural entered into a Bond Purchase Agreement between NW Natural and the institutional investors named as purchasers therein. The Bond Purchase Agreement provides for the issuance of (i) $100.0 million aggregate principal amount of NW Natural's First Mortgage Bonds (FMBs), 5.43% Series due 2053 (5.43% Bonds), (ii) $80.0 million aggregate principal amount of NW Natural's FMBs, 5.18% Series due 2034 (5.18% Bonds) and (iii) $50.0 million aggregate principal amount of NW Natural's FMBs, 5.23% Series due 2038 (5.23% Bonds) in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended. The 5.43% Bonds were issued on January 6, 2023, pursuant to the Twenty-fifth Supplemental Indenture to NW Natural's Mortgage and Deed of Trust, dated as of July 1, 1946, with Deutsche Bank Trust Company Americas as trustee (the Mortgage). The 5.18% Bonds and the 5.23% Bonds are expected to be issued on or about August 4, 2023, pursuant to the Twenty-sixth Supplemental Indenture to the Mortgage.

The 5.43% Bonds will bear interest at the rate of 5.43% per annum, payable semi-annually on January 6 and July 6 of each year, commencing July 6, 2023, and will mature on January 6, 2053. The 5.43% Bonds will be subject to redemption prior to maturity at the option of NW Natural, in whole or in part, (i) at any time prior to July 6, 2052, at a redemption price equal to 100% of the principal amount thereof plus a "make-whole" premium and accrued and unpaid interest thereon to the date of redemption, and

(ii) at any time on and after July 6, 2052, at 100% of the principal amount thereof plus accrued and unpaid interest thereon to the date of redemption.

The 5.18% Bonds will bear interest at the rate of 5.18% per annum, payable semi-annually on February 4 and August 4 of each year, commencing February 4, 2024, and will mature on August 4, 2034. The 5.18% Bonds will be subject to redemption prior to maturity at the option of NW Natural, in whole or in part, (i) at any time prior to May 4, 2034, at a redemption price equal to 100% of the principal amount thereof plus a “make-whole” premium and accrued and unpaid interest thereon to the date of redemption, and (ii) at any time on and after May 4, 2034, at 100% of the principal amount thereof plus accrued and unpaid interest thereon to the date of redemption.

The 5.23% Bonds will bear interest at the rate of 5.23% per annum, payable semi-annually on February 4 and August 4 of each year, commencing February 4, 2024, and will mature on August 4, 2038. The 5.23% Bonds will be subject to redemption prior to maturity at the option of NW Natural, in whole or in part, (i) at any time prior to May 4, 2038, at a redemption price equal to 100% of the principal amount thereof plus a “make-whole” premium and accrued and unpaid interest thereon to the date of redemption, and (ii) at any time on and after May 4, 2038, at 100% of the principal amount thereof plus accrued and unpaid interest thereon to the date of redemption.

In September 2022, NW Holdings entered into an 18-month credit agreement for $100.0 million and borrowed the full amount. The loan carries a variable interest rate based on the SOFR, resulting in a rate of 4.2% at December 31, 2022. The loan is due and payable on March 15, 2024. The credit agreement prohibits NW Holdings from permitting consolidated indebtedness to be greater than 70% of total capitalization, each as defined therein and calculated as of the end of each fiscal quarter. Failure to comply with this financial covenant would entitle the lenders to accelerate the maturity of the amounts outstanding under the credit agreement. NW Holdings was in compliance with this financial covenant as of December 31, 2022. In December 2022, NW Holdings entered into a swap to fix the interest rate on this debt beginning in January 2023 through the loan's maturity. See "Interest Rate Swap Agreements" below for more detail.

In September 2022, NWN Water entered into an 18-month credit agreement for $50.0 million and borrowed the full amount. The loan carries a variable interest rate based on the SOFR, resulting in a rate of 4.2% at December 31, 2022. The loan is due and payable on March 15, 2024. The credit agreement prohibits NWN Water and NW Holdings from permitting consolidated indebtedness to be greater than 70% of total capitalization, each as defined therein and calculated as of the end of each fiscal quarter. Failure to comply with this financial covenant would entitle the lenders to accelerate the maturity of the amounts outstanding under the credit agreement. NWN Water and NW Holdings were in compliance with this financial covenant as of December 31, 2022.

In July 2022, NW Natural entered into a Bond Purchase Agreement between NW Natural and the institutional investors named as purchasers therein for the issuance of $140.0 million aggregate principal amount of NW Natural's FMBs due in 2052 (the Bonds). The Bonds were issued on September 30, 2022. The Bonds bear interest at the rate of 4.78% per annum, payable semi-annually on March 30 and September 30 of each year, commencing March 30, 2023, and will mature on September 30, 2052. The Bonds are subject to redemption prior to maturity at the option of NW Natural, in whole or in part, (i) at any time prior to March 30, 2052, at a redemption price equal to 100% of the principal amount thereof plus a “make-whole” premium and accrued and unpaid interest thereon to the date of redemption, and (ii) at any time on and after March 30, 2052, at 100% of the principal amount thereof plus accrued and unpaid interest thereon to the date of redemption.

In November 2021, NW Natural issued $130.0 million of FMBs with an interest rate of 3.08% due in 2051. Issued as a sustainability bond, net proceeds from the sale of the FMBs were added to the general funds of NW Natural and used for general corporate purposes, while an amount equivalent to the net proceeds from the sale of the bonds was allocated to finance and/or refinance, in whole or in part, investments in one or more projects of NW Natural deemed to be an eligible project in the bond offering. An amount equivalent to the proceeds were allocated to expenditures related to RNG infrastructure, energy efficiency programs, expenditures related to the operations of our LEED Gold certified headquarters building, and expenditures and program investments related to enabling opportunities for diverse and small business enterprises.

In June 2021, NWN Water, a wholly-owned subsidiary of NW Holdings, entered into a five-year term loan agreement for $55.0 million. The loan carried an interest rate of 2.5% at December 31, 2022, which is based upon the one-month SOFR rate. The loan is guaranteed by NW Holdings and requires NW Holdings to maintain a consolidated indebtedness to total capitalization ratio of 70% or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. NW Holdings was in compliance with this covenant at December 31, 2022, with a consolidated indebtedness to total capitalization ratio of 57.6%. In December 2022, NW Holdings entered into a swap to fix the interest rate on this debt beginning in January 2023 through the loan's maturity. See "Interest Rate Swap Agreements" below for more detail.

Interest Rate Swap Agreements

NW Holdings and NWN Water entered into interest rate swap agreements with major financial institutions that effectively convert variable-rate debt to a fixed rate. Interest payments made between the effective date and expiration date are hedged by the swap agreements. The notional amount, effective date, expiration date and rate of the swap agreements are shown in the table below:

In millions	Notional Amount	Effective Date	Expiration Date	Fixed Rate
NW Holdings	$ 100.0	1/17/2023	3/15/2024	4.7 %
NWN Water	$ 55.0	1/19/2023	6/10/2026	3.8 %

Retirement of Long-Term Debt

The following NW Natural debentures were retired in the periods indicated:

	Year Ended December 31,		
In millions	2022	2021	2020
NW Natural First Mortgage Bonds:			
Series 5.37% due 2020	—	—	75
Series 9.05% due 2021	—	10	—
Series 3.18% due 2021	—	50	—
Total	$ —	$ 60	$ 75

In June 2019, NW Natural Water, a wholly-owned subsidiary of NW Holdings, entered into a two-year term loan agreement for $35.0 million. The loan was repaid in June 2021 upon its maturity date.

Maturities and Interest on Long-Term Debt

Maturities and payment of interest on long-term debt for each of the annual periods through December 31, 2027 and thereafter are as follows:

In millions	Long-term debt maturities	Interest on long-term debt
NW Natural:		
2023	$ 90.0	$ 53.9
2024	—	50.7
2025	30.0	50.2
2026	55.0	48.2
2027	64.7	44.8
Thereafter	895.0	783.0
NW Natural Total	$ 1,134.7	$ 1,030.8
Other NW Holdings:		
2023	$ 0.8	$ 12.8
2024	150.7	4.2
2025	0.7	2.7
2026	55.7	1.3
2027	0.7	0.1
Thereafter	2.6	0.3
Other NW Holdings Total	$ 211.2	$ 21.4
NW Holdings:		
2023	$ 90.8	$ 66.7
2024	150.7	54.9
2025	30.7	52.9
2026	110.7	49.5
2027	65.4	44.9
Thereafter	897.6	783.3
NW Holdings Total	$ 1,345.9	$ 1,052.2

Bankruptcy Ring-fencing Restrictions

As part of the ring-fencing conditions agreed upon with the OPUC and WUTC, NW Natural is required to have one director who is independent from NW Natural management and from NW Holdings and to issue one share of NW Natural preferred stock to an independent third party. NW Natural was in compliance with both of these ring-fencing provisions as of December 31, 2022 and 2021. NW Natural may file a voluntary petition for bankruptcy only if approved unanimously by the Board of Directors of NW Natural, including the independent director, and by the holder of the preferred share.

Cash Flows

Operating Activities

Changes in our operating cash flows are primarily affected by net income or loss, changes in working capital requirements, and other cash and non-cash adjustments to operating results.

In millions		2022		2021		2020
NW Natural cash provided by operating activities	$	145.2	$	141.5	$	148.5
NW Holdings cash provided by operating activities	$	147.7	$	160.4	$	145.3

2022 COMPARED TO 2021. The significant factors contributing to the $3.7 million increase at NW Natural cash flow provided by operating activities were as follows:

- $52.9 million increase in net deferred gas costs as the actual cost of gas during the year ended December 31, 2022 was higher than the rate embedded in the PGA. In addition, for the year ended December 31, 2021, actual gas costs were 21% above the PGA rate due to the 2021 cold weather event; and
- $12.6 million increase in accounts payable primarily due to a larger volume of gas purchased and the higher cost of gas; partially offset by
- $32.0 million increase in asset optimization revenue sharing bill credits to customers due to the 2021 cold weather event; and
- $32.1 million increase in accounts receivable and accrued unbilled revenue resulting from higher balances due to colder weather.

The $12.7 million decrease in NW Holdings cash flow provided by operating activities were driven by the above factors affecting NW Natural, in addition to lower prepaid income taxes in 2022 compared to 2021.

2021 COMPARED TO 2020. The significant factors contributing to the $7.0 million decrease at NW Natural cash flow provided by operating activities were as follows:

- $58.1 million increase in net deferred gas costs as the actual costs during the 2020-21 winter season were 21% above the PGA estimates primarily due to the 2021 cold weather event as opposed to gas costs in the 2019-20 winter season that were in line with estimates embedded in the PGA,
- $26.5 million decrease due to increased receivables; partially offset by
- $51.7 million increase in the regulatory incentive sharing mechanism related to revenues earned from Mist gas storage and asset management activities primarily related to the 2021 cold weather event, and
- $19.4 million of lower contributions to the defined benefit pension plan.

The $15.1 million increase in NW Holdings cash flow provided by operating activities were driven by the above factors affecting NW Natural, in addition to:

- $14.0 million increase due to lower income and other taxes, and
- $9.7 million increase due to lower deferred environmental expenses.

During the year ended December 31, 2022, NW Natural did not make any cash contributions to its qualified defined benefit pension plan, compared to $9.6 million in 2021 and $29.0 million in 2020. The American Rescue Plan, which was signed into law on March 11, 2021, includes a provision for pension relief that extends the amortization period for required contributions from 7 to 15 years and provides for the stabilization of interest rates used to calculate future required contributions. As a result, NW Natural does not expect to make any plan contributions during 2023. The amount and timing of future contributions will depend on market interest rates and investment returns on the plans' assets. See Note 10.

NW Holdings and NW Natural have lease and purchase commitments relating to our operating activities that are financed with cash flows from operations. For information on cash flow requirements related to leases and other purchase commitments, see Note 7 and Note 16.

Investing Activities

In millions		2022		2021		2020
NW Natural cash used in investing activities	$	(320.3)	$	(275.7)	$	(264.1)
NW Holdings cash used in investing activities	$	(435.5)	$	(300.1)	$	(294.3)

2022 COMPARED TO 2021. Cash used in investing activities increased $44.6 million at NW Natural and $135.4 million at NW Holdings, respectively. The increase at NW Natural is primary driven by an increase in capital expenditures of $40.4 million. The increase at NW Holdings is driven by the increase at NW Natural and $94.3 million in cash paid for water and wastewater acquisitions.

2021 COMPARED TO 2020. Cash used in investing activities increased $11.6 million at NW Natural and $5.8 million at NW Holdings, respectively. The increase at NW Natural is primary driven by an increase in capital expenditures of $12.2 million for customer growth, system reinforcement, and technology. The increase at NW Holdings is driven by the $14.5 million purchase of an equity method investment and $12.5 million of proceeds from the sale of discontinued operations in 2020, partially offset by a $37.0 million decrease in cash paid for acquisitions.

NW Natural capital expenditures for 2023 are expected to be in the range of $310 million to $350 million and for the five-year period from 2023 to 2027 are expected to range from $1.3 billion to $1.5 billion. NW Natural Water is expected to invest approximately $25 million in 2023 related to maintenance capital expenditures for water and wastewater utilities owned as of December 31, 2022, and for the five-year period from 2023 to 2027 capital expenditures are expected to invest approximately $90 million to $110 million.

The timing and amount of the core capital expenditures and projects for 2023 and the next five years could change based on regulation, growth, and cost estimates. Additional investments in our infrastructure during and after 2023 that are not incorporated in the estimates provided above will depend largely on additional regulations, growth, and expansion opportunities. Required funds for the investments are expected to be internally generated or financed with long-term debt or equity, as appropriate.

Financing Activities

In millions	2022	2021	2020
NW Natural cash provided by financing activities	$ 178.9	$ 139.3	$ 122.4
NW Holdings cash provided by financing activities	$ 301.6	$ 131.4	$ 171.8

2022 COMPARED TO 2021. Cash provided by financing activities increased $39.6 million at NW Natural primarily driven by $63.4 million in capital contributions by NW Holdings, partially offset by changes in debt.

Cash provided by financing activities increased $170.2 million at NW Holdings primarily due to cash proceeds of $191.1 million from the issuance of common stock and the ATM equity program, partially offset by changes in debt.

2021 COMPARED TO 2020. Cash provided by financing activities increased $16.9 million at NW Natural primarily driven by higher short-term debt borrowings of $297.6 million and $116.0 million in capital contributions by NW Holdings, partially offset by $390.1 million of lower proceeds from and repayments of commercial paper with maturities greater than 90 days.

Cash provided by financing activities decreased $40.4 million at NW Holdings primarily due to $390.1 million of lower proceeds from and repayments of commercial paper with maturities greater than 90 days, partially offset by higher other short-term debt borrowings of $319.6 million and cash proceeds of $17.5 million from the ATM equity program.

Pension Cost and Funding Status of Qualified Retirement Plans

NW Natural's pension costs are determined in accordance with accounting standards for compensation and retirement benefits. See "Application of Critical Accounting Policies and Estimates – *Pensions and Postretirement Benefits*" below. Pension expense for NW Natural's qualified defined benefit plan, which is allocated between operations and maintenance expenses and capital expenditures totaled $5.4 million in 2022, a decrease of $11.2 million from 2021. The fair market value of pension assets in this plan decreased to $280.3 million at December 31, 2022 from $399.2 million at December 31, 2021. The decrease was due to a loss on plan assets of $93.7 million and benefit payments of $25.2 million.

Contributions made to NW Natural's company-sponsored qualified defined benefit pension plan are based on actuarial assumptions and estimates, tax regulations, and funding requirements under federal law. The qualified defined benefit pension plan was underfunded by $101.3 million at December 31, 2022. The American Rescue Plan, which was signed into law on March 11, 2021, includes a provision for pension relief that extends the amortization period for required contributions from 7 to 15 years and provides for the stabilization of interest rates used to calculate future required contributions. As a result, NW Natural does not expect to make any plan contributions during 2023. The amount and timing of future contributions will depend on market interest rates and investment returns on the plan's assets. See Note 10 for information regarding employer contributions and estimated future benefit payments and other pension disclosures.

Contingent Liabilities
Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with accounting standards for contingencies. See “Application of Critical Accounting Policies and Estimates—*Environmental Contingencies*” below. At December 31, 2022, NW Natural's total estimated liability related to environmental sites was $118.8 million. See Note 17 and "Results of Operations—Regulatory Matters—Rate Mechanisms—*Environmental Cost Deferral and Recovery*" above.

NW Holdings is not currently party to any direct claims or litigation, though in the future it may be subject to claims and litigation arising in the ordinary course of business.

New Accounting Pronouncements
For a description of recent accounting pronouncements that may have an impact on our financial condition, results of operations, or cash flows, see Note 2.

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

In preparing financial statements in accordance with U.S. GAAP, management exercises judgment to assess the potential outcomes and related accounting impacts in the selection and application of accounting principles, including making estimates and assumptions that affect reported amounts of assets, liabilities, revenues, expenses, and related disclosures in the financial statements. Management considers critical accounting policies to be those which are most important to the representation of financial condition and results of operations and which require management’s most difficult and subjective or complex judgments, including accounting estimates that could result in materially different amounts if reported under different conditions or used different assumptions. Our most critical estimates and judgments for both NW Holdings and NW Natural include accounting for:
- regulatory accounting;
- revenue recognition;
- derivative instruments and hedging activities;
- pensions and postretirement benefits;
- income taxes;
- environmental contingencies; and
- impairment of long-lived assets and goodwill.

Management has discussed its current estimates and judgments used in the application of critical accounting policies with the Audit Committees of the Boards of NW Holdings and NW Natural. Within the context of critical accounting policies and estimates, management is not aware of any reasonably likely events or circumstances that would result in materially different amounts being reported.

Regulatory Accounting
The NGD segment is regulated by the OPUC and WUTC, which establish the rates designed to recover specific costs of providing regulatory services, and, to a certain extent, set forth special accounting treatment for certain regulatory transactions for which NW Natural records regulatory assets and liabilities. In general, the same accounting principles as non-regulated companies reporting under U.S. GAAP are used. However, authoritative guidance for regulated operations (regulatory accounting) requires different accounting treatment for regulated companies to show the effects of such regulation. For example, NW Natural accounts for the cost of gas using a PGA deferral and cost recovery mechanism, which is submitted for approval annually to the OPUC and WUTC. See "Results of Operations—Regulatory Matters—Rate Mechanisms—*Purchased Gas Adjustment*" above. There are other expenses and revenues that the OPUC or WUTC may require NW Natural to defer for recovery or refund in future periods. Regulatory accounting requires NW Natural to account for these types of deferred expenses (or deferred revenues) as regulatory assets (or regulatory liabilities) on the balance sheet. When the recovery of these regulatory assets from, or refund of regulatory liabilities to, customers is approved, NW Natural recognizes the expense or revenue on the income statement at the same time the adjustment to amounts is included in rates charged to customers.

The conditions that must be satisfied to adopt the accounting policies and practices of regulatory accounting include:
- an independent regulator sets rates;
- the regulator sets the rates to cover specific costs of delivering service; and
- the service territory lacks competitive pressures to reduce rates below the rates set by the regulator.

Because NW Natural's NGD operations satisfy all three conditions, NW Natural continues to apply regulatory accounting to NGD operations. Future accounting changes, regulatory changes, or changes in the competitive environment could require NW Natural to discontinue the application of regulatory accounting for some or all of our regulated businesses. This would require the write-off of those regulatory assets and liabilities that would no longer be probable of recovery from or refund to customers.

Based on current accounting and regulatory competitive conditions, NW Natural believes it is reasonable to expect continued application of regulatory accounting for NGD activities. Further, it is reasonable to expect the recovery or refund of NW Natural's regulatory assets and liabilities at December 31, 2022 through future customer rates. If it is determined that all or a portion of these regulatory assets or liabilities no longer meet the criteria for continued application of regulatory accounting, then NW Natural would be required to write-off the net unrecoverable balances against earnings in the period such determination is made. The net balance in regulatory asset and liability accounts was a net liability of $479.3 million and a net liability of $382.7 million as of December 31, 2022 and 2021, respectively. See Note 2 for more detail on regulatory balances.

Revenue Recognition

Revenues, which are derived primarily from the sale, transportation, and storage of natural gas, are recognized upon the delivery of gas commodity or services rendered to customers.

Accrued Unbilled Revenue

For a description of the policy regarding accrued unbilled revenue, most of which relates to the NGD business at NW Natural, see Note 2. The following table presents changes in key metrics if the estimated percentage of unbilled volume at December 31 was adjusted up or down by 1%:

	2022	
In millions	Up 1%	Down 1%
Unbilled revenue increase (decrease)[1]	$ 1.6	$ (1.6)
Margin increase (decrease)[1]	0.2	(0.2)
Net income before tax increase (decrease)[1]	0.2	(0.2)

[1] Includes impact of regulatory mechanisms including decoupling mechanism and excludes the impact of unbilled revenue from water services.

Derivative Instruments and Hedging Activities

NW Holdings and NW Natural have financial derivative policies that set forth guidelines for using financial derivative instruments to support prudent risk management strategies. These policies specifically prohibit the use of derivatives for trading or speculative purposes. Financial derivative contracts are utilized to hedge a portion of natural gas sale requirements. These contracts include swaps, options, and combinations of option contracts. NW Natural primarily uses these derivative financial instruments to manage commodity price variability. A small portion of NW Natural's derivative hedging strategy involves foreign currency exchange contracts.

Derivative instruments are recorded on the balance sheet at fair value. If certain regulatory conditions are met, then the derivative instrument fair value is recorded together with an offsetting entry to a regulatory asset or liability account pursuant to regulatory accounting, and no unrealized gain or loss is recognized in current income or loss. See "*Regulatory Accounting*" above for additional information. The gain or loss from the fair value of a derivative instrument subject to regulatory deferral is included in the recovery from, or refund to, NGD business customers in future periods. If a derivative contract is not subject to regulatory deferral, then the accounting treatment for unrealized gains and losses is recorded in accordance with accounting standards for derivatives and hedging which is either in current income or loss or in accumulated other comprehensive income or loss (AOCI or AOCL). Derivative contracts outstanding at December 31, 2022, 2021 and 2020 were measured at fair value using models or other market accepted valuation methodologies derived from observable market data. Estimates of fair value may change significantly from period-to-period depending on market conditions, notional amounts, and prices. These changes may have an impact on results of operations, but the impact would largely be mitigated due to the majority of derivative activities being subject to regulatory deferral treatment. For more information on derivative activity and associated regulatory treatment, see Note 2 and Note 15.

The following table summarizes the amount of gains realized from commodity price transactions for the last three years:

In millions	2022	2021	2020
NGD business net gain on commodity swaps	$ 107.8	$ 50.9	$ 2.3

Realized gains and losses from commodity hedges shown above were recorded in cost of gas and were, or will be, included in annual PGA rates.

NW Holdings and NWN Water also use financial derivatives to hedge interest rate risk in the form of pay-fixed interest rate swaps. Unrealized gains and losses related to these interest rate swap agreements are recorded in AOCI on the consolidated balance sheet.

Pensions and Postretirement Benefits

NW Natural maintains a qualified non-contributory defined benefit pension plan, non-qualified supplemental pension plans for eligible executive officers and certain key employees, and other postretirement employee benefit plans covering certain non-union employees. NW Natural also has a qualified defined contribution plan (Retirement K Savings Plan) for all eligible employees. Only the qualified defined benefit pension plan and Retirement K Savings Plan have plan assets, which are held in qualified trusts to fund the respective retirement benefits. The qualified defined benefit retirement plan for union and non-union employees was closed to new participants several years ago. Non-union and union employees hired or re-hired after December 31, 2006 and 2009, respectively, and employees of certain NW Holdings subsidiaries are provided an enhanced Retirement K Savings Plan benefit. The postretirement Welfare Benefit Plan for non-union employees was also closed to new participants several years ago.

Net periodic pension and postretirement benefit costs (retirement benefit costs) and projected benefit obligations (benefit obligations) are determined using a number of key assumptions, including discount rates, rate of compensation increases, retirement ages, mortality rates and an expected long-term return on plan assets. See Note 10.

Accounting standards also require balance sheet recognition of unamortized actuarial gains and losses and prior service costs in AOCI or AOCL, net of tax. However, the retirement benefit costs related to qualified defined benefit pension and postretirement benefit plans are generally recovered in rates charged to NGD customers, which are set based on accounting standards for pensions and postretirement benefit expenses. As such, NW Natural received approval from the OPUC to recognize the unamortized actuarial gains and losses and prior service costs as a regulatory asset or regulatory liability based on expected rate recovery, rather than including it as AOCI or AOCL under common equity. See "*Regulatory Accounting*" above and Note 2, "*Industry Regulation.*"

A number of factors, as discussed above, are considered in developing pension and postretirement benefit assumptions. For the December 31, 2022 measurement date, NW Natural reviewed and updated:

- the weighted-average discount rate assumptions for pensions increased from 2.71% for 2021 to 5.18% for 2022, and the weighted-average discount rate assumptions for other postretirement benefits increased from 2.72% for 2021 to 5.19% for 2022. The new rate assumptions were determined for each plan based on a matching of benchmark interest rates to the estimated cash flows, which reflect the timing and amount of future benefit payments. Benchmark interest rates are drawn from the FTSE Above Median Curve, which consists of high quality bonds rated AA- or higher by S&P or Aa3 or higher by Moody's;
- the expected annual rate of future compensation is separately determined for bargaining unit and non-bargaining unit employees. The rate assumption ranges from 4.5% to 5.0% in 2023, 4.0% to 6.0% in 2024 and 4.0% thereafter.
- the expected long-term return on qualified defined benefit plan assets increased to 7.50% in 2022 from 7.00% in 2021; and
- other key assumptions, which were based on actual plan experience and actuarial recommendations.

At December 31, 2022, the net pension liability (benefit obligations less market value of plan assets) for the defined benefit pension plan decreased $3.3 million compared to 2021. The decrease in the net pension liability is primarily due to the $118.9 million decrease in plan assets and the $122.3 million decrease to the pension benefit obligation. The liability for non-qualified plans decreased $6.9 million, and the liability for other postretirement benefits decreased $7.3 million in 2022.

The expected long-term rate of return on plan assets is determined by averaging the expected earnings for the target asset portfolio. In developing expected return, historical actual performance, and long-term return projections are analyzed, which gives consideration to the current asset mix and target asset allocation.

NW Natural believes its pension assumptions are appropriate based on plan design and an assessment of market conditions. The following shows the sensitivity of retirement benefit costs and benefit obligations to changes in certain actuarial assumptions:

Dollars in millions	Change in Assumption	Impact on 2022 Retirement Benefit Costs	Impact on Retirement Benefit Obligations at Dec. 31, 2022
Discount rate:	(0.25)%		
Qualified defined benefit plans		$ 1.6	$ 10.5
Non-qualified plans		—	0.1
Other postretirement benefits		0.1	0.5
Expected long-term return on plan assets:	(0.25)%		
Qualified defined benefit plans		0.9	N/A

Income Taxes

Valuation Allowances

Deferred tax assets are recognized to the extent that these assets are believed to be more likely than not to be realized. In making such a determination, available positive and negative evidence is considered, including future reversals of existing taxable temporary differences, projected future taxable income, tax-planning strategies, and results of recent operations. NW Holdings and NW Natural have determined that all recorded deferred tax assets are more likely than not to be realized as of December 31, 2022. See Note 11.

Uncertain Tax Benefits

The calculation of tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in the jurisdictions in which we operate. A tax benefit from a material uncertain tax position will only be recognized when it is more likely than not that the position, or some portion thereof, will be sustained upon examination, including resolution of any related appeals or litigation processes, on the basis of the technical merits. NW Holdings and NW Natural participate in the Compliance Assurance Process (CAP) with the Internal Revenue Service (IRS). Under the CAP program companies work with the IRS to identify and resolve material tax matters before the federal income tax return is filed each year. No reserves for uncertain tax benefits were recorded during 2022, 2021, or 2020. See Note 11.

Tax Legislation

When significant proposed or enacted changes in income tax rules occur, we consider whether there may be a material impact to our financial position, results of operations, cash flows, or whether the changes could materially affect existing assumptions used in making estimates of tax related balances.

The final tangible property regulations applicable to all taxpayers were issued on September 13, 2013 and were generally effective for taxable years beginning on or after January 1, 2014. In addition, procedural guidance related to the regulations was issued under which taxpayers may make accounting method changes to comply with the regulations. We have evaluated the regulations and do not anticipate any material impact. However, unit-of-property guidance applicable to natural gas distribution networks has not yet been issued and is expected in the near future. We will further evaluate the effect of these regulations after this guidance is issued, but believe the current method is materially consistent with the new regulations and do not expect this additional guidance to have a material effect on our financial statements.

Regulatory Matters

Regulatory tax assets and liabilities are recorded to the extent it is probable they will be recoverable from, or refunded to, customers in the future. At December 31, 2022 and 2021, NW Natural had net regulatory income tax assets of $10.2 million and $12.4 million, respectively, representing future rate recovery of deferred tax liabilities resulting from differences in NGD plant financial statement and tax bases and NGD plant removal costs. These regulatory assets are currently being recovered through customer rates. At December 31, 2022 and 2021, regulatory income tax assets of $2.9 million and $2.4 million, respectively, were recorded by NW Natural, representing probable future rate recovery of deferred tax liabilities resulting from the equity portion of AFUDC. At December 31, 2021, regulatory income tax asset of $0.4 million was recorded by NW Natural, representing future recovery of Oregon CAT that was deferred between January 1, 2020 and October 31, 2020. In October 2020, the OPUC issued an order providing for recovery of deferred Oregon CAT as well as CAT incurred prospectively beginning November 1, 2020. This asset was fully recovered as of December 31, 2022.

At December 31, 2022 and 2021, regulatory liability balances, representing the estimated net benefit to NGD customers resulting from the change in deferred taxes as a result of the TCJA, of $181.4 million and $189.6 million, respectively, were recorded by NW Natural. These balances include a gross up for income taxes of $48.0 million and $50.2 million, respectively.

The TCJA includes specific guidance for determining the shortest time period over which the portion of this regulatory liability resulting from accelerated cost recovery of NGD plant may accrue to the benefit of customers to avoid incurring federal normalization penalties. However, it is anticipated that until such time that customers receive the direct benefit of this regulatory liability, the balance, net of the additional gross up for income taxes, will continue to provide an indirect benefit to customers by reducing the NGD rate base which determines customer rates for service.

Environmental Contingencies

Environmental liabilities are accounted for in accordance with accounting standards under the loss contingency guidance when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable. Amounts recorded for environmental contingencies take numerous factors into consideration, including, among other variables, changes in enacted laws, regulatory orders, estimated remediation costs, interest rates, insurance proceeds, participation by other parties, timing of payments, and the input of legal counsel and third-party experts. Accordingly, changes in any of these variables or other factual circumstances could have a material impact on the amounts recorded for our environmental liabilities. For a complete discussion of environmental accounting policies refer to Note 2. For a discussion of current environmental sites and liabilities refer to Note 17. In addition, for information regarding the regulatory treatment of these costs and NW Natural's regulatory recovery mechanism, see "Results of Operations—Regulatory Matters—Rate Mechanisms—*Environmental Cost Deferral and Recovery*" above.

Impairment of Long-Lived Assets and Goodwill

Long-Lived Assets

We review the carrying value of long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets might not be recoverable. Factors that would necessitate an impairment assessment of long-lived assets include a significant adverse change in the extent or manner in which the asset is used, a significant adverse change in legal factors or business climate that could affect the value of the asset, or a significant decline in the observable market value or expected future cash flows of the asset, among others.

When such factors are present, we assess the recoverability by determining whether the carrying value of the asset will be recovered through expected future cash flows. An asset is determined to be impaired when the carrying value of the asset exceeds the expected undiscounted future cash flows from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss for the difference between the carrying value and the fair value of the long-lived assets. Fair value is estimated using appropriate valuation methodologies, which may include an estimate of discounted cash flows.

Goodwill and Business Combinations

In a business combination, goodwill is initially measured as any excess of the acquisition-date fair value of the consideration transferred over the acquisition-date fair value of the net identifiable assets acquired.

The carrying value of goodwill is reviewed annually during the fourth quarter, or whenever events or changes in circumstance indicate that such carrying values may not be recoverable.

NW Holdings' policy for goodwill assessments begins with a qualitative analysis in which events and circumstances are evaluated, including macroeconomic conditions, industry and market conditions, regulatory environments, and the overall financial performance of the reporting unit. If the qualitative assessment indicates that the carrying value may be at risk of recoverability, a quantitative evaluation is performed to measure the carrying value against the fair value of the reporting unit. This evaluation may involve the assessment of future cash flows and other subjective factors for which uncertainty exists and could impact the estimation of future cash flows. These factors include, but are not limited to, the amount and timing of future cash flows, future growth rates, and the discount rate. Unforeseen events and changes in circumstances or market conditions could adversely affect these estimates, which could result in an impairment charge. A qualitative assessment was performed during the fourth quarter of 2022 which indicated a quantitative assessment was not required; thus, no goodwill impairment was recorded. See Note 2 and Note 14 for additional information.

Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as the aggregate of the consideration transferred, measured at fair value at the acquisition date, and the fair value of any non-controlling interest in the acquiree. Acquisition-related costs are expensed as incurred. When NW Natural acquires a business, it assesses the financial assets acquired and liabilities assumed for appropriate classification and designation in accordance with the contractual terms, economic circumstances and pertinent conditions as of the acquisition date. When there is substantial judgment or uncertainty around the fair value of acquired assets, we may engage a third party expert to assist in determining the fair values of certain assets or liabilities.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

NW Holdings and NW Natural are exposed to various forms of market risk including commodity supply risk, commodity price risk, interest rate risk, foreign currency risk, credit risk and weather risk. The following describes NW Holdings' and NW Natural's exposure to these risks, as applicable.

Commodity Supply Risk

NW Natural enters into spot, short-term, and long-term natural gas supply contracts, along with associated pipeline transportation contracts, to manage commodity supply risk. Historically, NW Natural has arranged for physical delivery of an adequate supply of gas, including gas in Mist storage and off-system storage facilities, to meet expected requirements of core NGD customers. NW Natural's long-term gas supply contracts are primarily index-based and subject to monthly re-pricing, a strategy that is intended to substantially mitigate credit exposure to physical gas counterparties. Absolute notional amounts under physical gas contracts related to open positions on derivative instruments were 463 million therms and 432 million therms as of December 31, 2022 and 2021, respectively.

Commodity Price Risk

Natural gas commodity prices are subject to market fluctuations due to unpredictable factors including weather, pipeline transportation congestion, drilling technologies, market speculation, and other factors that affect supply and demand. Commodity price risk is hedged with financial swaps, storage and physical gas reserves from a long-term investment in working interests in gas leases operated by Jonah Energy. These hedges are generally included in NW Natural's annual PGA filing for recovery, subject to a regulatory prudence review. Notional amounts under financial derivative contracts were $359.5 million and $159.9 million as of December 31, 2022 and 2021, respectively. The fair value of financial swaps, based on market prices at December 31, 2022, was an unrealized gain of $150.6 million, which would result in cash inflows of $134.3 million in 2023, $10.8 million in 2024, and $5.5 million in 2025.

Interest Rate Risk

NW Holdings and NW Natural are exposed to interest rate risk primarily associated with new debt financing needed to fund capital requirements, including future contractual obligations and maturities of long-term and short-term debt. Interest rate risk is primarily managed through the issuance of fixed-rate debt with varying maturities. NW Holdings and NW Natural may also enter into financial derivative instruments, including interest rate swaps, options and other hedging instruments, to manage and mitigate interest rate exposure. NW Holdings and NWN Water entered into interest rate swaps transactions for a total notional amount of $155 million to manage variable interest rate risk in December 2022. NW Natural did not have any outstanding interest rate swaps as of December 31, 2022 or 2021.

Foreign Currency Risk

The costs of certain pipeline and off-system storage services purchased from Canadian suppliers are subject to changes in the value of the Canadian currency in relation to the U.S. currency. Foreign currency forward contracts are used to hedge against fluctuations in exchange rates for NW Natural's commodity-related demand and reservation charges paid in Canadian dollars. Notional amounts under foreign currency forward contracts were $7.6 million and $6.3 million as of December 31, 2022 and 2021, respectively. If all of the foreign currency forward contracts had been settled on December 31, 2022, a loss of $165 thousand would have been realized. See Note 15.

Credit Risk

Credit Exposure to Natural Gas Suppliers

Certain gas suppliers have either relatively low credit ratings or are not rated by major credit rating agencies. To manage this supply risk, NW Natural purchases gas from a number of different suppliers at liquid exchange points. NW Natural evaluates and monitors suppliers' creditworthiness and maintains the ability to require additional financial assurances, including deposits, letters of credit, or surety bonds, in case a supplier defaults. In the event of a supplier's failure to deliver contracted volumes of gas, the NGD business would need to replace those volumes at prevailing market prices, which may be higher or lower than the original transaction prices. NW Natural expects these costs would be subject to its PGA sharing mechanism discussed above. Since most of NW Natural's commodity supply contracts are priced at the daily or monthly market index price tied to liquid exchange points, and NW Natural has adequate storage flexibility, NW Natural believes it is unlikely a supplier default would have a material adverse effect on its financial condition or results of operations.

Credit Exposure to Financial Derivative Counterparties

Based on estimated fair value at December 31, 2022, NW Natural's overall credit exposure relating to commodity contracts was $150.6 million. We generally have credit exposure to financial commodity swap derivative counterparties when forward gas prices exceed our hedge prices, which was the case with all financial swap counterparties at December 31, 2022. NW Natural's credit exposure also includes interest rate swap and foreign exchange forward counterparties, neither of which were significant at December 31, 2022. NW Natural's financial derivatives policy requires counterparties to have at least an investment-grade credit rating at the time the derivative instrument is entered into and specific limits on the contract amount and duration based on each counterparty's credit rating. NW Natural actively monitors and manages derivative credit exposure and places counterparties on hold for trading purposes or requires cash collateral, letters of credit, or guarantees as circumstances warrant.

The following table summarizes NW Natural's overall financial swap and option credit exposure, based on estimated fair value, and the corresponding counterparty credit ratings. The table uses credit ratings from S&P and Moody's, reflecting the higher of the S&P or Moody's rating or a middle rating if the entity is split-rated with more than one rating level difference:

	Financial Derivative Position by Credit Rating Unrealized Fair Value Gain (Loss)	
In millions	2022	2021
AA/Aa	$ 77.9	$ 44.3
A/A	72.7	6.9
Total	$ 150.6	$ 51.2

In most cases, NW Natural also mitigates the credit risk of financial derivatives by having master netting arrangements with counterparties which provide for making or receiving net cash settlements. Transactions of the same type in the same currency that have settlement on the same day with a single counterparty are netted and a single payment is delivered or received depending on which party is due funds.

Additionally, NW Natural has master contracts in place with each derivative counterparty, most of which include provisions for posting or calling for collateral. Generally, NW Natural can obtain cash or marketable securities as collateral with one day's notice. Various collateral management strategies are used to reduce liquidity risk. The collateral provisions vary by counterparty but are not expected to result in the significant posting of collateral, if any. NW Natural has performed stress tests on the portfolio and concluded the liquidity risk from collateral calls is not material. Derivative credit exposure is primarily with investment grade counterparties rated AA-/Aa3 or higher. Contracts are diversified across counterparties, business types and countries to reduce credit and liquidity risk.

At December 31, 2022, financial derivative commodity credit risk on a volumetric basis was geographically concentrated 28% in the United States and 71% in Canada, based on counterparties' location. At December 31, 2021, financial derivative commodity credit risk on a volumetric basis was geographically concentrated 37% in the United States and 63% in Canada with our counterparties.

Credit Exposure to Insurance Companies

Credit exposure to insurance companies for loss or damage claims could be material. NW Holdings and NW Natural regularly monitor the financial condition of insurance companies who provide general liability insurance policy coverage to NW Holdings, NW Natural, their predecessors, and their subsidiaries.

Weather Risk

NW Natural has a weather normalization mechanism in Oregon; however, it is exposed to weather risk primarily from NGD business operations. A large percentage of NGD margin is volume driven, and current rates are based on an assumption of average weather. NW Natural's weather normalization mechanism in Oregon is for residential and small commercial customers, which is intended to stabilize the recovery of NGD business fixed costs and reduce fluctuations in customers' bills due to colder or warmer than average weather. Customers in Oregon are allowed to opt out of the weather normalization mechanism. As of December 31, 2022, approximately 7% of Oregon customers had opted out. In addition to the Oregon customers opting out, Washington residential and commercial customers account for approximately 12% of our total customer base and are not covered by weather normalization. The combination of Oregon and Washington customers not covered by a weather normalization mechanism is 19% of all residential and commercial customers. See "Results of Operations—Regulatory Matters—Rate Mechanisms—*WARM*" above.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Supplemental Schedules Omitted

All other schedules are omitted because of the absence of the conditions under which they are required or because the required information is included elsewhere in the financial statements.

NW HOLDINGS MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

NW Holdings management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) or 15d-15(f) under the Securities Exchange Act of 1934, as amended. NW Holdings' internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP). NW Holdings' internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions involving company assets;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit the preparation of financial statements in accordance with U.S. GAAP, and that receipts and expenditures are being made only in accordance with authorizations of management and the NW Holdings Board of Directors; and

(iii) provide reasonable assurance regarding prevention or timely detection of the unauthorized acquisition, use, or disposition of NW Holdings' assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements or fraud. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

NW Holdings management assessed the effectiveness of NW Holdings' internal control over financial reporting as of December 31, 2022. In making this assessment, NW Holdings management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework (2013)*.

Based on NW Holdings management's assessment and those criteria, NW Holdings management has concluded that it maintained effective internal control over financial reporting as of December 31, 2022.

The effectiveness of internal control over financial reporting as of December 31, 2022 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears in this annual report.

/s/ David H. Anderson
David H. Anderson
President and Chief Executive Officer

/s/ Frank H. Burkhartsmeyer
Frank H. Burkhartsmeyer
Senior Vice President and Chief Financial Officer

February 24, 2023

NW NATURAL MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

NW Natural management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) or 15d-15(f) under the Securities Exchange Act of 1934, as amended. NW Natural's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP). NW Natural's internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions involving company assets;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit the preparation of financial statements in accordance with U.S. GAAP, and that receipts and expenditures are being made only in accordance with authorizations of management and the NW Natural Board of Directors; and

(iii) provide reasonable assurance regarding prevention or timely detection of the unauthorized acquisition, use, or disposition of NW Natural's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements or fraud. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

NW Natural management assessed the effectiveness of NW Natural's internal control over financial reporting as of December 31, 2022. In making this assessment, NW Natural management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework (2013)*.

Based on NW Natural management's assessment and those criteria, NW Natural management has concluded that it maintained effective internal control over financial reporting as of December 31, 2022.

/s/ David H. Anderson
David H. Anderson
President and Chief Executive Officer

/s/ Frank H. Burkhartsmeyer
Frank H. Burkhartsmeyer
Senior Vice President and Chief Financial Officer

February 24, 2023

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Northwest Natural Holding Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Northwest Natural Holding Company and its subsidiaries (the "Company") as of December 31, 2022 and 2021, and the related consolidated statements of comprehensive income (loss), of shareholders' equity and of cash flows for each of the three years in the period ended December 31, 2022, including the related notes and financial statement schedules listed in the accompanying index (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for the Effects of Regulatory Matters

As described in Note 2 to the consolidated financial statements, there were $457.9 million of regulatory assets and $938.2 million of regulatory liabilities as of December 31, 2022. As disclosed by management, the Company has operations that are subject to the actions of regulators which establish rates in general rate cases and other proceedings which are designed to recover specific costs of providing regulatory services for which management records regulatory assets and liabilities. Regulatory accounting requires management to account for deferred expenses (or deferred revenues) as regulatory assets (or regulatory liabilities) on the balance sheet. When the recovery of these regulatory assets from, or refund of regulatory liabilities to, customers is approved, management recognizes the expense or revenue on the income statement at the same time the adjustment to amounts is included in rates charged to customers.

The principal considerations for our determination that performing procedures relating to the Company’s accounting for the effects of regulatory matters is a critical audit matter are the significant judgment by management in assessing the potential outcomes and related accounting impacts of rate cases and other proceedings. This in turn led to a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence obtained related to the recovery of regulatory assets and the settlement of regulatory liabilities.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management’s assessment of rates cases and other proceedings, including the probability of recovery of regulatory assets and the settlement of regulatory liabilities and related accounting and disclosure impacts. These procedures also included, among others (i) evaluating the reasonableness of management’s assessment regarding the probability of recovery of regulatory assets and settlement of regulatory liabilities, (ii) evaluating the sufficiency of the disclosures in the consolidated financial statements, and (iii) testing the regulatory assets and liabilities, including those subject to regulatory proceedings, also involved considering the provisions and formulas outlined in rate orders, other regulatory correspondence, and the application of relevant regulatory precedents.

/s/ PricewaterhouseCoopers LLP
Portland, Oregon
February 24, 2023

We have served as the Company’s auditor since 1997.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of Northwest Natural Gas Company:

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Northwest Natural Gas Company and its subsidiaries (the “Company”) as of December 31, 2022 and 2021, and the related consolidated statements of comprehensive income (loss), of shareholder's equity and of cash flows for each of the three years in the period ended December 31, 2022, including the related notes and financial statement schedule listed in the accompanying index (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for the Effects of Regulatory Matters

As described in Note 2 to the consolidated financial statements, there were $457.9 million of regulatory assets and $937.2 million of regulatory liabilities as of December 31, 2022. As disclosed by management, the Company has operations that are subject to the actions of regulators which establish rates in general rate cases and other proceedings which are designed to recover specific costs of providing regulatory services for which management records regulatory assets and liabilities. Regulatory accounting requires management to account for deferred expenses (or deferred revenues) as regulatory assets (or regulatory liabilities) on the balance sheet. When the recovery of these regulatory assets from, or refund of regulatory liabilities to, customers is approved, management recognizes the expense or revenue on the income statement at the same time the adjustment to amounts is included in rates charged to customers.

The principal considerations for our determination that performing procedures relating to the Company’s accounting for the effects of regulatory matters is a critical audit matter are the significant judgment by management in assessing the potential outcomes and related accounting impacts of rate cases and other proceedings. This in turn led to a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence obtained related to the recovery of regulatory assets and the settlement of regulatory liabilities.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management’s assessment of rates cases and other proceedings, including the probability of recovery of regulatory assets and the settlement of regulatory liabilities and related accounting and disclosure impacts. These procedures also included, among others (i) evaluating the reasonableness of management’s assessment regarding the probability of recovery of regulatory assets and settlement of regulatory liabilities, (ii) evaluating the sufficiency of the disclosures in the consolidated financial statements, and (iii) testing the regulatory assets and liabilities, including those subject to regulatory proceedings, also involved considering the provisions and formulas outlined in rate orders, other regulatory correspondence, and the application of relevant regulatory precedents.

/s/ PricewaterhouseCoopers LLP
Portland, Oregon
February 24, 2023

We have served as the Company’s auditor since 1997.

NORTHWEST NATURAL HOLDING COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
In thousands, except per share data	2022	2021	2020
Operating revenues	$ 1,037,353	$ 860,400	$ 773,679
Operating expenses:			
Cost of gas	429,635	292,314	262,755
Operations and maintenance	224,667	204,227	180,129
Environmental remediation	12,389	9,938	9,691
General taxes	41,031	38,633	35,078
Revenue taxes	41,826	34,740	30,291
Depreciation	116,707	113,534	103,683
Other operating expenses	3,621	3,897	3,701
Total operating expenses	869,876	697,283	625,328
Income from operations	167,477	163,117	148,351
Other income (expense), net	1,203	(12,559)	(13,944)
Interest expense, net	53,247	44,486	43,052
Income before income taxes	115,433	106,072	91,355
Income tax expense	29,130	27,406	21,082
Net income from continuing operations	86,303	78,666	70,273
Income from discontinued operations, net of tax	—	—	6,508
Net income	86,303	78,666	76,781
Other comprehensive income (loss):			
Change in employee benefit plan liability, net of taxes of $(1,511) for 2022, $(219) for 2021, and $1,025 for 2020	4,195	593	(2,848)
Amortization of non-qualified employee benefit plan liability, net of taxes of $(286) for 2022, $(320) for 2021, and $(244) for 2020	795	905	679
Unrealized gain on interest rate swaps, net of taxes of $(47) for 2022	129	—	—
Comprehensive income	$ 91,422	$ 80,164	$ 74,612
Average common shares outstanding:			
Basic	33,934	30,702	30,541
Diluted	33,984	30,752	30,599
Earnings from continuing operations per share of common stock:			
Basic	$ 2.54	$ 2.56	$ 2.30
Diluted	2.54	2.56	2.30
Earnings from discontinued operations per share of common stock:			
Basic	$ —	$ —	$ 0.21
Diluted	—	—	0.21
Earnings per share of common stock:			
Basic	$ 2.54	$ 2.56	$ 2.51
Diluted	2.54	2.56	2.51

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL HOLDING COMPANY
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
In thousands	2022	2021
Assets:		
Current assets:		
Cash and cash equivalents	$ 29,270	$ 18,559
Accounts receivable	168,906	101,495
Accrued unbilled revenue	89,048	82,169
Allowance for uncollectible accounts	(3,296)	(2,018)
Regulatory assets	117,491	72,391
Derivative instruments	194,412	48,130
Inventories	87,096	57,262
Other current assets	61,286	59,288
Total current assets	744,213	437,276
Non-current assets:		
Property, plant, and equipment	4,261,566	3,997,243
Less: Accumulated depreciation	1,147,166	1,125,873
Total property, plant, and equipment, net	3,114,400	2,871,370
Regulatory assets	340,432	314,579
Derivative instruments	5,045	10,730
Other investments	95,704	89,278
Operating lease right of use asset, net	73,429	75,049
Assets under sales-type leases	134,302	138,995
Goodwill	149,283	70,570
Other non-current assets	91,518	56,757
Total non-current assets	4,004,113	3,627,328
Total assets	$ 4,748,326	$ 4,064,604

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL HOLDING COMPANY
CONSOLIDATED BALANCE SHEETS

In thousands	As of December 31, 2022	As of December 31, 2021
Liabilities and equity:		
Current liabilities:		
Short-term debt	$ 258,200	$ 389,500
Current maturities of long-term debt	90,697	345
Accounts payable	180,667	133,486
Taxes accrued	15,625	15,520
Interest accrued	10,169	7,503
Regulatory liabilities	248,582	112,281
Derivative instruments	28,728	10,402
Operating lease liabilities	1,514	1,296
Other current liabilities	64,552	54,432
Total current liabilities	898,734	724,765
Long-term debt	1,246,167	1,044,587
Deferred credits and other non-current liabilities:		
Deferred tax liabilities	366,022	340,231
Regulatory liabilities	689,578	658,332
Pension and other postretirement benefit liabilities	149,143	166,684
Derivative instruments	20,838	412
Operating lease liabilities	78,965	79,468
Other non-current liabilities	123,438	114,979
Total deferred credits and other non-current liabilities	1,427,984	1,360,106
Commitments and contingencies (see Note 16 and Note 17)		
Equity:		
Common stock - no par value; authorized 100,000 shares; issued and outstanding 35,525 and 31,129 at December 31, 2022 and 2021, respectively	805,253	590,771
Retained earnings	376,473	355,779
Accumulated other comprehensive loss	(6,285)	(11,404)
Total equity	1,175,441	935,146
Total liabilities and equity	$ 4,748,326	$ 4,064,604

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL HOLDING COMPANY
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

In thousands	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Equity
Balance at December 31, 2019	$ 558,282	$ 318,450	$ (10,733)	$ 865,999
Comprehensive income (loss)	—	76,781	(2,169)	74,612
Dividends on common stock, $1.91 per share	—	(58,708)	—	(58,708)
Stock-based compensation	4,361	—	—	4,361
Shares issued pursuant to equity based plans	2,469	—	—	2,469
Balance at December 31, 2020	565,112	336,523	(12,902)	888,733
Comprehensive income (loss)	—	78,666	1,498	80,164
Dividends on common stock, $1.92 per share	—	(59,410)	—	(59,410)
Stock-based compensation	3,615	—	—	3,615
Shares issued pursuant to equity based plans	4,543	—	—	4,543
Issuance of common stock, net of issuance costs	17,501	—	—	17,501
Balance at December 31, 2021	590,771	355,779	(11,404)	935,146
Comprehensive income (loss)	—	86,303	5,119	91,422
Dividends on common stock, $1.93 per share	—	(65,609)	—	(65,609)
Stock-based compensation	3,228	—	—	3,228
Shares issued pursuant to equity based plans	2,978	—	—	2,978
Issuance of common stock, net of issuance costs	208,276	—	—	208,276
Balance at December 31, 2022	$ 805,253	$ 376,473	$ (6,285)	$ 1,175,441

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL HOLDING COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
In thousands	2022	2021	2020
Operating activities:			
Net income	$ 86,303	$ 78,666	$ 76,781
Adjustments to reconcile net income to cash provided by operations:			
Depreciation	116,707	113,534	103,683
Regulatory amortization of gas reserves	5,589	13,897	17,779
Deferred income taxes	17,410	14,617	18,667
Qualified defined benefit pension plan expense	5,351	16,556	18,370
Contributions to qualified defined benefit pension plans	—	(9,590)	(28,980)
Deferred environmental expenditures, net	(18,160)	(18,187)	(27,871)
Environmental remediation expense	12,389	9,938	9,691
Gain on sale of discontinued operations, net of tax	—	—	(5,902)
Asset optimization revenue sharing bill credits	(41,102)	(9,053)	(16,970)
Other	21,558	20,622	10,028
Changes in assets and liabilities:			
Receivables, net	(76,454)	(44,128)	(16,799)
Inventories	(29,269)	(14,571)	1,262
Income and other taxes	6,908	3,292	(10,710)
Accounts payable	24,508	12,118	(15,910)
Deferred gas costs	12,334	(40,541)	17,590
Asset optimization revenue sharing	28,937	44,458	(7,244)
Decoupling mechanism	10,922	(5,206)	2,884
Cloud-based software	(23,908)	(7,407)	(4,265)
Other, net	(12,351)	(18,662)	1,340
Discontinued operations	—	—	1,894
Cash provided by operating activities	147,672	160,353	145,318
Investing activities:			
Capital expenditures	(338,602)	(293,892)	(273,016)
Acquisitions, net of cash acquired	(94,279)	(1,289)	(38,263)
Leasehold improvement expenditures	(761)	(1,364)	(7,878)
Proceeds from the sale of assets	870	3,926	8,149
Purchase of equity method investment	(1,000)	(14,450)	—
Proceeds from sale of equity method investment	—	7,000	7,000
Proceeds from sale of discontinued operations	—	—	12,500
Other	(1,688)	(54)	1,654
Discontinued operations	—	—	(4,423)
Cash used in investing activities	(435,460)	(300,123)	(294,277)

	Year Ended December 31, 2022	2021	2020
Financing activities:			
Proceeds from common stock issued, net	208,561	17,501	—
Long-term debt issued	290,000	185,000	150,000
Long-term debt retired	—	(95,000)	(75,000)
Proceeds from term loan due within one year	—	100,000	150,000
Repayment of term loan	—	(100,000)	(150,000)
Proceeds from commercial paper, maturities greater than three months	—	—	195,025
Repayments of commercial paper, maturities greater than three months	—	(195,025)	—
Changes in other short-term debt, net	(131,300)	280,000	(39,600)
Cash dividend payments on common stock	(62,771)	(55,919)	(55,420)
Other	(2,858)	(5,121)	(3,228)
Cash provided by financing activities	301,632	131,436	171,777
Increase (decrease) in cash, cash equivalents and restricted cash	13,844	(8,334)	22,818
Cash, cash equivalents and restricted cash, beginning of period	27,120	35,454	12,636
Cash, cash equivalents and restricted cash, end of period	$ 40,964	$ 27,120	$ 35,454
Supplemental disclosure of cash flow information:			
Interest paid, net of capitalization	$ 50,823	$ 43,719	$ 42,651
Income taxes paid, net of refunds	2,779	10,555	13,644

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
In thousands	2022	2021	2020
Operating revenues	$ 1,014,339	$ 843,057	$ 758,748
Operating expenses:			
Cost of gas	429,861	292,538	262,980
Operations and maintenance	204,845	188,762	168,869
Environmental remediation	12,389	9,938	9,691
General taxes	40,151	38,150	34,459
Revenue taxes	41,627	34,600	30,291
Depreciation	112,957	110,504	101,586
Other operating expenses	3,135	3,332	3,232
Total operating expenses	844,965	677,824	611,108
Income from operations	169,374	165,233	147,640
Other income (expense), net	(436)	(12,745)	(15,116)
Interest expense, net	46,338	42,983	40,866
Income before income taxes	122,600	109,505	91,658
Income tax expense	31,036	28,333	21,095
Net income	91,564	81,172	70,563
Other comprehensive income (loss):			
Change in employee benefit plan liability, net of taxes of $(1,511) for 2022, $(219) for 2021, and $1,025 for 2020	4,195	593	(2,848)
Amortization of non-qualified employee benefit plan liability, net of taxes of $(286) for 2022, $(320) for 2021, and $(244) for 2020	795	905	679
Comprehensive income	$ 96,554	$ 82,670	$ 68,394

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
In thousands	2022	2021
Assets:		
Current assets:		
Cash and cash equivalents	$ 12,977	$ 12,271
Accounts receivable	165,607	99,780
Accrued unbilled revenue	87,482	82,028
Receivables from affiliates	634	261
Allowance for uncollectible accounts	(3,079)	(1,962)
Regulatory assets	117,491	72,391
Derivative instruments	194,236	48,130
Inventories	86,207	56,752
Other current assets	57,269	47,378
Total current assets	718,824	417,029
Non-current assets:		
Property, plant, and equipment	4,148,547	3,931,640
Less: Accumulated depreciation	1,137,231	1,119,361
Total property, plant, and equipment, net	3,011,316	2,812,279
Regulatory assets	340,407	314,539
Derivative instruments	5,045	10,730
Other investments	80,110	74,786
Operating lease right of use asset, net	72,720	74,987
Assets under sales-type leases	134,302	138,995
Other non-current assets	89,994	55,027
Total non-current assets	3,733,894	3,481,343
Total assets	$ 4,452,718	$ 3,898,372

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

In thousands	As of December 31, 2022	2021
Liabilities and equity:		
Current liabilities:		
Short-term debt	$ 170,200	$ 245,500
Current maturities of long-term debt	89,942	—
Accounts payable	177,590	131,475
Payables to affiliates	9,175	1,248
Taxes accrued	15,426	15,476
Interest accrued	8,900	7,296
Regulatory liabilities	248,553	112,281
Derivative instruments	28,728	10,402
Operating lease liabilities	1,363	1,273
Other current liabilities	62,019	53,591
Total current liabilities	811,896	578,542
Long-term debt	1,035,935	986,495
Deferred credits and other non-current liabilities:		
Deferred tax liabilities	362,353	337,717
Regulatory liabilities	688,599	657,350
Pension and other postretirement benefit liabilities	149,143	166,684
Derivative instruments	20,838	412
Operating lease liabilities	78,345	79,431
Other non-current liabilities	114,527	113,934
Total deferred credits and other non-current liabilities	1,413,805	1,355,528
Commitments and contingencies (see Note 16 and Note 17)		
Equity:		
Common stock	614,903	435,515
Retained earnings	582,593	553,696
Accumulated other comprehensive loss	(6,414)	(11,404)
Total equity	1,191,082	977,807
Total liabilities and equity	$ 4,452,718	$ 3,898,372

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF SHAREHOLDER'S EQUITY

In thousands	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Equity
Balance at December 31, 2019	$ 319,557	$ 513,372	$ (10,733)	$ 822,196
Comprehensive income (loss)	—	70,563	(2,169)	68,394
Dividends on common stock	—	(55,355)	—	(55,355)
Other	(51)	—	—	(51)
Balance at December 31, 2020	319,506	528,580	(12,902)	835,184
Comprehensive income (loss)	—	81,172	1,498	82,670
Dividends on common stock	—	(56,056)	—	(56,056)
Capital contributions from parent	116,009	—	—	116,009
Balance at December 31, 2021	435,515	553,696	(11,404)	977,807
Comprehensive income (loss)	—	91,564	4,990	96,554
Dividends on common stock	—	(62,667)	—	(62,667)
Capital contributions from parent	179,388	—	—	179,388
Balance at December 31, 2022	$ 614,903	$ 582,593	$ (6,414)	$ 1,191,082

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

In thousands	Year Ended December 31, 2022	2021	2020
Operating activities:			
Net income	$ 91,564	$ 81,172	$ 70,563
Adjustments to reconcile net income to cash provided by operations:			
Depreciation	112,957	110,504	101,586
Regulatory amortization of gas reserves	5,589	13,897	17,779
Deferred income taxes	16,288	13,223	4,645
Qualified defined benefit pension plan expense	5,351	16,556	18,370
Contributions to qualified defined benefit pension plans	—	(9,590)	(28,980)
Deferred environmental expenditures, net	(18,160)	(18,187)	(27,871)
Environmental remediation expense	12,389	9,938	9,691
Asset optimization revenue sharing bill credits	(41,102)	(9,053)	(16,970)
Other	20,448	18,517	9,945
Changes in assets and liabilities:			
Receivables, net	(75,177)	(43,030)	(16,540)
Inventories	(28,890)	(14,427)	1,539
Income and other taxes	6,729	(10,405)	10,832
Accounts payable	21,375	8,728	(18,909)
Deferred gas costs	12,334	(40,541)	17,590
Asset optimization revenue sharing	28,937	44,458	(7,244)
Decoupling mechanism	10,922	(5,206)	2,884
Cloud-based software	(23,908)	(7,407)	(4,265)
Other, net	(12,455)	(17,653)	3,872
Cash provided by operating activities	145,191	141,494	148,517
Investing activities:			
Capital expenditures	(318,686)	(278,237)	(266,048)
Leasehold improvement expenditures	(761)	(1,364)	(7,878)
Proceeds from the sale of assets	870	3,926	8,149
Other	(1,688)	(54)	1,654
Cash used in investing activities	(320,265)	(275,729)	(264,123)
Financing activities:			
Long-term debt issued	140,000	130,000	150,000
Long-term debt retired	—	(60,000)	(75,000)
Proceeds from term loan due within one year	—	100,000	150,000
Repayment of term loan	—	(100,000)	(150,000)
Proceeds from commercial paper, maturities greater than three months	—	—	195,025
Repayment of commercial paper, maturities greater than three months	—	(195,025)	—
Changes in other short-term debt, net	(75,300)	209,000	(88,600)
Cash contributions received from parent	179,388	116,009	—
Cash dividend payments on common stock	(62,667)	(56,056)	(55,355)
Other	(2,508)	(4,600)	(3,632)
Cash provided by financing activities	178,913	139,328	122,438
Increase in cash, cash equivalents and restricted cash	3,839	5,093	6,832
Cash, cash equivalents and restricted cash, beginning of period	20,832	15,739	8,907
Cash, cash equivalents and restricted cash, end of period	$ 24,671	$ 20,832	$ 15,739
Supplemental disclosure of cash flow information:			
Interest paid, net of capitalization	$ 44,813	$ 42,395	$ 40,624
Income taxes paid, net of refunds	5,990	26,451	6,100

See Notes to Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND PRINCIPLES OF CONSOLIDATION

The accompanying consolidated financial statements represent the respective, consolidated financial results of NW Holdings and NW Natural and all respective companies that each registrant directly or indirectly controls, either through majority ownership or otherwise. This is a combined report of NW Holdings and NW Natural, which includes separate consolidated financial statements for each registrant.

NW Natural's regulated natural gas distribution activities are reported in the natural gas distribution (NGD) segment. The NGD segment is NW Natural's core operating business and serves residential, commercial, and industrial customers in Oregon and southwest Washington. The NGD segment is the only reportable segment for NW Holdings and NW Natural. All other activities, water and wastewater businesses, and other investments are aggregated and reported as other at their respective registrant.

NW Holdings and NW Natural consolidate all entities in which they have a controlling financial interest. Investments in corporate joint ventures and partnerships that NW Holdings does not directly or indirectly control, and for which it is not the primary beneficiary, include NNG Financial's investment in Kelso-Beaver Pipeline and NWN Water's investment in Avion Water Company, Inc., which are accounted for under the equity method. NW Natural RNG Holding Company, LLC holds an investment in Lexington Renewable Energy, LLC, which is also accounted for under the equity method. See Note 13 for activity related to equity method investments. NW Holdings and its direct and indirect subsidiaries are collectively referred to herein as NW Holdings, and NW Natural and its direct and indirect subsidiaries are collectively referred to herein as NW Natural. The consolidated financial statements of NW Holdings and NW Natural are presented after elimination of all intercompany balances and transactions.

In June 2018, NWN Gas Storage, a wholly-owned subsidiary of NW Natural at the time and now a wholly-owned subsidiary of NW Holdings, entered into a Purchase and Sale Agreement that provided for the sale of all of the membership interests in its wholly-owned subsidiary, Gill Ranch Storage, LLC (Gill Ranch). We concluded that the sale of Gill Ranch qualified as assets and liabilities held for sale and discontinued operations. As such, the results of Gill Ranch were presented as a discontinued operation for NW Holdings for all periods presented on the consolidated statements of comprehensive income and cash flows, and the assets and liabilities associated with Gill Ranch were classified as discontinued operations assets and liabilities on the NW Holdings consolidated balance sheet. The sale closed on December 4, 2020. See Note 18 for additional information.

Notes to the consolidated financial statements reflect the activity of continuing operations for both NW Holdings and NW Natural for all periods presented, unless otherwise noted. Certain reclassifications have been made to conform prior period information to the current presentation. The reclassifications did not have a material effect on our consolidated financial statements.

2. SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America (U.S. GAAP) requires management to make estimates and assumptions that affect reported amounts in the consolidated financial statements and accompanying notes. Actual amounts could differ from those estimates, and changes would most likely be reported in future periods. Management believes the estimates and assumptions used are reasonable.

Industry Regulation

NW Holdings' principal business is to operate as a holding company for NW Natural and its other subsidiaries. NW Natural's principal business is the distribution of natural gas, which is regulated by the OPUC and WUTC. NW Natural also has natural gas storage services, which are regulated by the FERC, and to a certain extent by the OPUC and WUTC. Additionally, certain of NW Holdings' subsidiaries own water businesses, which are regulated by the public utility commission in the state in which the water utility is located, which is currently Oregon, Washington, Idaho, Texas and Arizona. Wastewater businesses, to the extent they are regulated, are generally regulated by the public utility commissions in the state in which the wastewater utility is located, which is currently Texas and Arizona. Accounting records and practices of the regulated businesses conform to the requirements and uniform system of accounts prescribed by these regulatory authorities in accordance with U.S. GAAP. The businesses in which customer rates are regulated by the OPUC, WUTC, IPUC, PUTC, ACC and FERC have approved cost-based rates which are intended to allow such businesses to earn a reasonable return on invested capital.

In applying regulatory accounting principles, NW Holdings and NW Natural capitalize or defer certain costs and revenues as regulatory assets and liabilities pursuant to orders of the applicable state public utility commission, which provide for the recovery of revenues or expenses from, or refunds to, utility customers in future periods, including a return or a carrying charge in certain cases.

Amounts NW Natural deferred as regulatory assets and liabilities were as follows:

In thousands	Regulatory Assets 2022	Regulatory Assets 2021
NW Natural:		
Current:		
Unrealized loss on derivatives[1]	$ 28,728	$ 10,402
Gas costs	61,223	35,641
Environmental costs[2]	7,392	6,694
Decoupling[3]	—	969
Pension balancing[4]	7,131	7,131
Income taxes	2,208	2,568
Other[5]	10,809	8,986
Total current	$ 117,491	$ 72,391
Non-current:		
Unrealized loss on derivatives[1]	$ 20,838	$ 412
Pension balancing[4]	32,997	38,302
Income taxes	10,943	12,609
Pension and other postretirement benefit liabilities	101,413	116,440
Environmental costs[2]	104,253	94,636
Gas costs	22,355	15,477
Other[5]	47,608	36,663
Total non-current	$ 340,407	$ 314,539
Other (NW Holdings)	25	40
Total non-current -NW Holdings	$ 340,432	$ 314,579

In thousands	Regulatory Liabilities 2022	Regulatory Liabilities 2021
NW Natural:		
Current:		
Gas costs	$ 4,121	$ 70
Unrealized gain on derivatives[1]	194,236	48,130
Decoupling[3]	14,026	4,475
Income taxes[6]	7,166	8,192
Asset optimization revenue sharing	26,368	45,124
Other[5]	2,636	6,290
Total current - NW Natural	$ 248,553	$ 112,281
Other (NW Holdings)	29	—
Total current - NW Holdings	$ 248,582	$ 112,281
Non-current:		
Gas costs	$ 12,644	$ 250
Unrealized gain on derivatives[1]	5,045	10,730
Decoupling[3]	3,814	3,412
Income taxes[6]	174,212	181,404
Accrued asset removal costs[7]	467,742	445,952
Asset optimization revenue sharing	8,401	1,810
Other[5]	16,741	13,792
Total non-current - NW Natural	$ 688,599	$ 657,350
Other (NW Holdings)	979	982
Total non-current -NW Holdings	$ 689,578	$ 658,332

(1) Unrealized gains or losses on derivatives are non-cash items and, therefore, do not earn a rate of return or a carrying charge. These amounts are recoverable through natural gas distribution rates as part of the annual Purchased Gas Adjustment (PGA) mechanism when realized at settlement.
(2) Refer to the Environmental Cost Deferral and Recovery table in Note 17 for a description of environmental costs.
(3) This deferral represents the margin adjustment resulting from differences between actual and expected volumes.
(4) Refer to Note 10 for information regarding the deferral of pension expenses.

(5) Balances consist of deferrals and amortizations under approved regulatory mechanisms and typically earn a rate of return or carrying charge.
(6) This balance represents estimated amounts associated with the Tax Cuts and Jobs Act. See Note 11.
(7) Estimated costs of removal on certain regulated properties are collected through rates. See "Accounting Policies—*Plant, Property, and Accrued Asset Removal Costs*" below.

The amortization period for NW Natural's regulatory assets and liabilities ranges from less than one year to an indeterminable period. Regulatory deferrals for gas costs payable are generally amortized over 12 months beginning each November 1 following the gas contract year during which the deferred gas costs are recorded. Similarly, most other regulatory deferred accounts are amortized over 12 months. However, certain regulatory account balances, such as income taxes, environmental costs, pension liabilities, and accrued asset removal costs, are large and tend to be amortized over longer periods once NW Natural has agreed upon an amortization period with the respective regulatory agency.

We believe all costs incurred and deferred at December 31, 2022 are prudent. All regulatory assets are reviewed annually for recoverability, or more often if circumstances warrant. If we should determine that all or a portion of these regulatory assets no longer meet the criteria for continued application of regulatory accounting, then NW Natural would be required to write-off the net unrecoverable balances in the period such determination is made.

Regulatory interest income of $7.0 million and $6.1 million and regulatory interest expense of $2.0 million and $1.3 million was recognized within other income (expense), net for the years ended December 31, 2022 and 2021, respectively.

Environmental Regulatory Accounting

See Note 17 for information about the SRRM and OPUC orders regarding implementation.

COVID-19 Impact

During 2020, our regulated utilities received approval in their respective jurisdictions to defer certain financial impacts associated with COVID-19 such as bad debt expense, financing costs to secure liquidity, lost revenues related to late fees and reconnection fees, and other COVID-19 related costs, net of offsetting direct expense reductions associated with COVID-19. As of December 31, 2022, we believe that approximately $18.7 million of the financial effects related to COVID-19 are recoverable. As part of the 2022 Oregon general rate case, NW Natural received approval from the OPUC to recover the 2020 and 2021 COVID-19 deferral beginning November 1, 2022. Approximately $10.9 million will be amortized over a two-year period and NW Natural may request recovery of the remaining amount in the third year. Included in the total balance is approximately $3.4 million of forgone late fee revenue that will be recognized in future periods as billed. Beginning January 2023, NW Natural will no longer defer any COVID-19 related costs in Oregon. NW Natural expects to recover its COVID-19 deferrals in Washington in a future proceeding.

New Accounting Standards

NW Natural and NW Holdings consider the applicability and impact of all accounting standards updates (ASUs) issued by the Financial Accounting Standards Board (FASB). ASUs not listed below were assessed and determined to be either not applicable or are expected to have minimal impact on consolidated financial position or results of operations.

Recently Adopted Accounting Pronouncements

REFERENCE RATE REFORM. In March 2020, the FASB issued ASU 2020-04, "Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting." The purpose of the amendment is to provide optional expedients and exceptions for applying generally accepted accounting principles (GAAP) to contracts, hedging relationships, and other transactions affected by reference rate reform if certain criteria are met. The amendments in this ASU apply only to contracts, hedging relationships, and other transactions that reference London Inter-Bank Offered Rate (LIBOR) or another reference rate expected to be discontinued because of reference rate reform.

In January 2021, the FASB issued ASU 2021-01, "Reference Rate Reform (Topic 848): Scope." The purpose of the amendment is to clarify guidance on reference rate reform activities, specifically related to accounting for derivative contracts and certain hedging relationships affected by changes in the interest rates used for discounting, margining, and contract price alignment (the "discounting transition"). The amendments in ASUs 2020-04 and 2021-01 are effective for all entities as of March 12, 2020 through December 31, 2022.

In December 2022, the FASB issued ASU 2022-06, "Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848." The purpose of the amendment is to defer the sunset date of Topic 848 from December 31, 2022, to December 31, 2024, after which entities will no longer be permitted to apply the relief in Topic 848. The objective of the guidance in Topic 848 is to provide temporary relief during the transition period. The Board included a sunset provision within Topic 848 based on expectations of when the London Interbank Offered Rate (LIBOR) would cease being published. We do not expect the ASUs to materially affect the financial statements and disclosures of NW Holdings or NW Natural.

LEASES. In July 2021, the FASB issued ASU 2021-05, "Leases (Topic 842), Lessors - Certain Leases with Variable Lease Payments." The purpose of the amendment is to require lessors to account for certain lease transactions that contain variable lease payments as operating leases. The amendments in this ASU are intended to eliminate the recognition of any day-one loss associated with certain sales-type and direct-financing lease transactions. The changes do not impact lessee accounting. The new guidance was effective on January 1, 2022 and adopted using a prospective approach. The adoption did not materially affect the financial statements and disclosures of NW Holdings or NW Natural.

Accounting Policies

The accounting policies discussed below apply to both NW Holdings and NW Natural.

Plant, Property, and Accrued Asset Removal Costs

Plant and property are stated at cost, including capitalized labor, materials, and overhead. In accordance with regulatory accounting standards, the cost of acquiring and constructing long-lived plant and property generally includes an allowance for funds used during construction (AFUDC) or capitalized interest. AFUDC represents the regulatory financing cost incurred when debt and equity funds are used for construction (see "*AFUDC*" below). When constructed assets are subject to market-based rates rather than cost-based rates, the financing costs incurred during construction are included in capitalized interest in accordance with U.S. GAAP, not as regulatory financing costs under AFUDC.

In accordance with long-standing regulatory treatment, our depreciation rates consist of three components: one based on the average service life of the asset, a second based on the estimated salvage value of the asset, and a third based on the asset's estimated cost of removal. We collect, through rates, the estimated cost of removal on certain regulated properties through depreciation expense, with a corresponding offset to accumulated depreciation. These removal costs are non-legal obligations as defined by regulatory accounting guidance. Therefore, we have included these costs as non-current regulatory liabilities rather than as accumulated depreciation on our consolidated balance sheets. In the rate setting process, the liability for removal costs is treated as a reduction to the net rate base on which the NGD business has the opportunity to earn its allowed rate of return.

The costs of NGD plant retired or otherwise disposed of are removed from NGD plant and charged to accumulated depreciation for recovery or refund through future rates. Gains from the sale of regulated assets are generally deferred and refunded to customers. For assets not related to NGD, we record a gain or loss upon the disposal of the property, and the gain or loss is recorded in operating income or loss in the consolidated statements of comprehensive income.

The provision for depreciation of NGD property, plant, and equipment is recorded under the group method on a straight-line basis with rates computed in accordance with depreciation studies approved by regulatory authorities. The weighted-average depreciation rate for NGD assets in service was approximately 3.0% for 2022, 2021 and 2020, reflecting the approximate weighted-average economic life of the property. This includes 2022 weighted-average depreciation rates for the following asset categories: 2.5% for transmission and distribution plant, 2.1% for gas storage facilities, 6.1% for general plant, and 6.7% for intangible and other fixed assets.

AFUDC. Certain additions to NGD plant include AFUDC, which represents the net cost of debt and equity funds used during construction. AFUDC is calculated using actual interest rates for debt and authorized rates for ROE, if applicable. If short-term debt balances are less than the total balance of construction work in progress, then a composite AFUDC rate is used to represent interest on all debt funds, shown as a reduction to interest charges, and on ROE funds, shown as other income. While cash is not immediately recognized from recording AFUDC, it is realized in future years through rate recovery resulting from the higher NGD cost of service. Our composite AFUDC rate was 2.8% in 2022, 0.7% in 2021, and 1.9% in 2020.

IMPAIRMENT OF LONG-LIVED ASSETS. We review the carrying value of long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. Factors that would necessitate an impairment assessment of long-lived assets include a significant adverse change in the extent or manner in which the asset is used, a significant adverse change in legal factors or business climate that could affect the value of the asset, or a significant decline in the observable market value or expected future cash flows of the asset, among others.

When such factors are present, we assess the recoverability by determining whether the carrying value of the asset will be recovered through expected future cash flows. An asset is determined to be impaired when the carrying value of the asset exceeds the expected undiscounted future cash flows from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss for the difference between the carrying value and the fair value of the long-lived assets. Fair value is estimated using appropriate valuation methodologies, which may include an estimate of discounted cash flows.

Cash and Cash Equivalents

For purposes of reporting cash flows, cash and cash equivalents include cash on hand plus highly liquid investment accounts with original maturity dates of three months or less. At December 31, 2022, NW Holdings had outstanding checks of $5.8 million, substantially all of which is recorded at NW Natural, and at December 31, 2021, NW Holdings had no outstanding checks. These balances are included in accounts payable in the NW Holdings and NW Natural balance sheets.

Restricted cash is primarily comprised of funds from public purpose charges for programs that assist low-income customers with bill payments or energy efficiency. These balances are included in other current assets in the NW Holdings and NW Natural balance sheets. There were no transfers between restricted cash and cash and cash equivalents during the years ended December 31, 2022 and 2021. Prior period amounts have been reclassified to conform prior period information to the current presentation.

The following table provides a reconciliation of the cash, cash equivalents and restricted cash balances at NW Holdings as of December 31, 2022 and 2021:

	December 31,	
In thousands	2022	2021
Cash and cash equivalents	$ 29,270	$ 18,559
Restricted cash included in other current assets	11,694	8,561
Cash, cash equivalents and restricted cash	$ 40,964	$ 27,120

The following table provides a reconciliation of the cash, cash equivalents and restricted cash balances at NW Natural as of December 31, 2022 and 2021:

	December 31,	
In thousands	2022	2021
Cash and cash equivalents	$ 12,977	$ 12,271
Restricted cash included in other current assets	11,694	8,561
Cash, cash equivalents and restricted cash	$ 24,671	$ 20,832

Revenue Recognition and Accrued Unbilled Revenue
Revenues, derived primarily from the sale and transportation of natural gas, are recognized upon delivery of gas or water, or service to customers. Revenues include accruals for gas or water delivered but not yet billed to customers based on estimates of deliveries from meter reading dates to month end (accrued unbilled revenue). Accrued unbilled revenue is dependent upon a number of factors that require management's judgment, including total natural gas receipts and deliveries, customer use of natural gas or water by billing cycle, and weather factors. Accrued unbilled revenue is reversed the following month when actual billings occur. NW Holdings' accrued unbilled revenue at December 31, 2022 and 2021 was $89.0 million and $82.2 million, respectively, substantially all of which is accrued unbilled revenue at NW Natural.

Revenues not related to NGD are derived primarily from Interstate Storage Services, asset management activities at the Mist gas storage facility, and other investments and business activities. At the Mist underground storage facility, revenues are primarily firm service revenues in the form of fixed monthly reservation charges. In addition, we also have asset management service revenue from an independent energy marketing company that optimizes commodity, storage, and pipeline capacity release transactions. Under this agreement, guaranteed asset management revenue is recognized using a straight-line, pro-rata methodology over the term of each contract. Revenues earned above the guaranteed amount are recognized as they are earned.

Revenue Taxes
Revenue-based taxes are primarily franchise taxes, which are collected from customers and remitted to taxing authorities. Revenue taxes are included in operating expenses in the statements of comprehensive income for NW Holdings and NW Natural. Revenue taxes at NW Holdings were $41.8 million, $34.7 million, and $30.3 million for 2022, 2021, and 2020, respectively.

Accounts Receivable and Allowance for Uncollectible Accounts
Accounts receivable consist primarily of amounts due for natural gas sales and transportation services to NGD customers, plus amounts due for gas storage services. NW Holdings and NW Natural establish allowances for uncollectible accounts (allowance) for trade receivables, including accrued unbilled revenue, based on the aging of receivables, collection experience of past due account balances including payment plans, and historical trends of write-offs as a percent of revenues. A specific allowance is established and recorded for large individual customer receivables when amounts are identified as unlikely to be partially or fully recovered. Inactive accounts are written-off against the allowance after they are 120 days past due or when deemed uncollectible. Differences between the estimated allowance and actual write-offs will occur based on a number of factors, including changes in economic conditions, customer creditworthiness, and natural gas prices. The allowance for uncollectible accounts is adjusted quarterly, as necessary, based on information currently available.

ALLOWANCE FOR TRADE RECEIVABLES. The payment term of our NGD receivables is generally 15 days. For these short-term receivables, it is not expected that forecasted economic conditions would significantly affect the loss estimates under stable economic conditions. For extreme situations like a financial crisis, natural disaster, and the economic slowdown caused by the COVID-19 pandemic, we enhanced our review and analysis.

For the 2022 residential and commercial uncollectible provision, we primarily followed our standard methodology, which includes assessing historical write-off trends and current information on delinquent accounts. Beginning October 1, 2022, new collection rules from the OPUC applied to residential and commercial customers. This included enhanced protections for low-income customers, a return to pre-pandemic time payment arrangements terms, revised disconnection rules during the heating season, and other items. As a result of these Oregon rule changes and our recent collection process experience, we augmented our provision review in the third and fourth quarter for Oregon accounts in the following categories: closed or inactive accounts aged less than 120 days, accounts on payment plans, and all other open accounts not on payment plans. For industrial accounts, we continue to assess the provision on an account-by-account basis with specific reserves taken as necessary. NW Natural will continue to closely monitor and evaluate our accounts receivable and the provision for uncollectible accounts.

The following table presents the activity related to the NW Holdings provision for uncollectible accounts by pool, substantially all of which is related to NW Natural's accounts receivable:

	As of December 31, 2021	Year ended December 31, 2022		As of December 31, 2022
In thousands	Beginning Balance	Provision recorded, net of adjustments	Write-offs recognized, net of recoveries	Ending Balance
Allowance for uncollectible accounts:				
Residential	$ 1,460	$ 1,974	$ (1,062)	$ 2,372
Commercial	178	546	(324)	400
Industrial	67	186	(65)	188
Accrued unbilled and other	313	185	(162)	336
Total	$ 2,018	$ 2,891	$ (1,613)	$ 3,296

ALLOWANCE FOR NET INVESTMENTS IN SALES-TYPE LEASES. NW Natural currently holds two net investments in sales-type leases, with substantially all of the net investment balance related to the North Mist natural gas storage agreement with Portland General Electric (PGE) which is billed under an OPUC-approved rate schedule. See Note 7 for more information on the North Mist lease. Due to the nature of this service, PGE may recover the costs of the lease through general rate cases. Therefore, we expect the risk of loss due to the credit of this lessee to be remote. As such, no allowance for uncollectibility was recorded for our sales-type lease receivables. NW Natural will continue monitoring the credit health of the lessees and the overall economic environment, including the economic factors closely tied to the financial health of our current and future lessees.

Inventories

NGD gas inventories, which consist of natural gas in storage for NGD customers, are stated at the lower of weighted-average cost or net realizable value. The regulatory treatment of these inventories provides for cost recovery in customer rates. NGD gas inventories injected into storage are priced in inventory based on actual purchase costs, and those withdrawn from storage are charged to cost of gas during the period they are withdrawn at the weighted-average inventory cost.

Gas storage inventories mainly consist of natural gas received as fuel-in-kind from storage customers. Gas storage inventories are valued at the lower of average cost or net realizable value. Cushion gas is not included in inventory balances, is recorded at original cost, and is classified as a long-term plant asset.

Materials and supplies inventories consist of inventories both related to and unrelated to NGD and are stated at the lower of average cost or net realizable value.

NW Natural's NGD and gas storage inventories totaled $61.9 million and $37.4 million at December 31, 2022 and 2021, respectively. At December 31, 2022 and 2021, NW Holdings' materials and supplies inventories, which are comprised primarily of NW Natural's materials and supplies, totaled $23.5 million and $19.9 million, respectively.

During 2022 and 2021, NW Natural entered into certain agreements to purchase renewable thermal certificates (RTCs). RTCs are initially recorded at cost and subsequently assessed for impairment based on the lower-of-cost or market model. NW Natural's RTCs inventory totaled $1.7 million at December 31, 2022, and all RTCs purchased during 2021 were retired or used on customers behalf prior to December 31, 2021.

Gas Reserves

Gas reserves are payments to acquire and produce natural gas reserves. Gas reserves are stated at cost, adjusted for regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet. The current portion is calculated based on expected gas deliveries within the next fiscal year. NW Natural recognizes regulatory amortization of this asset on a volumetric basis calculated using the estimated gas reserves and the estimated therms extracted and sold each month. The amortization of gas reserves is recorded to cost of gas along with gas production revenues and production costs. See Note 13.

Derivatives

NW Natural's derivatives are measured at fair value and recognized as either assets or liabilities on the balance sheet. Changes in the fair value of the derivatives are recognized in earnings unless specific regulatory or hedge accounting criteria are met. Accounting for derivatives and hedges provides an exception for contracts intended for normal purchases and normal sales for which physical delivery is probable. In addition, certain derivative contracts are approved by regulatory authorities for recovery or refund through customer rates. Accordingly, the changes in fair value of these approved contracts are deferred as regulatory assets or liabilities pursuant to regulatory accounting principles. NW Natural's financial derivatives generally qualify for deferral under regulatory accounting. NW Natural's index-priced physical derivative contracts also qualify for regulatory deferral accounting treatment.

Derivative contracts entered into for NGD requirements after the annual PGA rate has been set and maturing during the PGA year are subject to the PGA incentive sharing mechanism. In Oregon, NW Natural participates in a PGA sharing mechanism under which it is required to select either an 80% or 90% deferral of higher or lower gas costs such that the impact on current earnings from the gas cost sharing is either 20% or 10% of gas cost differences compared to PGA prices, respectively. For each of the PGA years in Oregon beginning November 1, 2022, 2021, and 2020, NW Natural selected the 90% deferral of gas cost differences. In Washington, 100% of the differences between the PGA prices and actual gas costs are deferred. See Note 15.

NW Holdings and NW Natural have financial derivative policies that set forth guidelines for using selected derivative products to support prudent risk management strategies within designated parameters. NW Natural's objective for using derivatives is to decrease the volatility of gas prices and cash flows without speculative risk. The use of derivatives is permitted only after the risk exposures have been identified, are determined to exceed acceptable tolerance levels, and are determined necessary to support normal business activities. NW Natural does not enter into derivative instruments for trading purposes. All commodity and foreign exchange derivatives are currently held at NW Natural, and interest rate swaps are held at NW Holdings and NWN Water.

Fair Value

In accordance with fair value accounting, we use the following fair value hierarchy for determining inputs for our debt, pension plan assets, and derivative fair value measurements:

- Level 1: Valuation is based on quoted prices for identical instruments traded in active markets;
- Level 2: Valuation is based on quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and model-based valuation techniques for which all significant assumptions are observable in the market; and
- Level 3: Valuation is generated from model-based techniques that use significant assumptions not observable in the market. These unobservable assumptions reflect our own estimates of assumptions market participants would use in valuing the asset or liability.

In addition, the fair value for certain pension trust investments is determined using Net Asset Value per share (NAV) as a practical expedient, and therefore they are not classified within the fair value hierarchy. These investments primarily consist of institutional investment products.

When developing fair value measurements, it is our policy to use quoted market prices whenever available or to maximize the use of observable inputs and minimize the use of unobservable inputs when quoted market prices are not available. Fair values are primarily developed using industry-standard models that consider various inputs including: (a) quoted future prices for commodities; (b) forward currency prices; (c) time value; (d) volatility factors; (e) current market and contractual prices for underlying instruments; (f) market interest rates and yield curves; (g) credit spreads; and (h) other relevant economic measures. NW Natural considers liquid points for natural gas hedging to be those points for which there are regularly published prices in a nationally recognized publication or where the instruments are traded on an exchange.

Goodwill and Business Combinations

NW Holdings, through its wholly-owned subsidiary NWN Water and NWN Water's wholly-owned subsidiaries, has completed various acquisitions that resulted in the recognition of goodwill. Goodwill is measured as the excess of the acquisition-date fair value of the consideration transferred over the acquisition-date fair value of the net identifiable assets assumed. Adjustments are recorded during the measurement period to finalize the allocation of the purchase price. The carrying value of goodwill is reviewed annually during the fourth quarter, or whenever events or changes in circumstance indicate that such carrying values may not be recoverable. The goodwill assessment policy begins with a qualitative analysis in which events and circumstances are evaluated, including macroeconomic conditions, industry and market conditions, regulatory environments, and overall financial performance of the reporting unit. If the qualitative assessment indicates that the carrying value may be at risk of recoverability, a quantitative evaluation is performed to measure the carrying value of the goodwill against the fair value of the reporting unit. The reporting unit is determined primarily based on current operating segments and the level of review provided by the Chief Operating Decision Maker (CODM) and/or segment management on the operating segment's financial results. Reporting units are evaluated periodically for changes in the corporate environment.

As of December 31, 2022 and 2021, NW Holdings had goodwill of $149.3 million and $70.6 million, respectively. All of NW Holdings' goodwill was acquired through the business combinations completed by NWN Water and its wholly-owned subsidiaries. No impairment charges were recorded as a result of the fourth quarter goodwill impairment assessment.

Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as the aggregate of the consideration transferred, measured at fair value at the acquisition date, and the fair value of any non-controlling interest in the acquiree. Acquisition-related costs are expensed as incurred. When NW Natural acquires a business, it assesses the financial assets acquired and liabilities assumed for appropriate classification and designation in accordance with the contractual terms, economic circumstances and pertinent conditions as of the acquisition date. When there is substantial judgment or uncertainty around the fair value of acquired assets, we may engage a third party expert to assist in determining the fair values of certain assets or liabilities.

Income Taxes
We account for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, deferred tax assets and liabilities are determined on the basis of the differences between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the enactment date period unless, for NW Natural, a regulatory order specifies deferral of the effect of the change in tax rates over a longer period of time.

For NW Natural, deferred income tax assets and liabilities are also recognized for temporary differences where the deferred income tax benefits or expenses have previously been flowed through in the ratemaking process of the NGD business. Regulatory tax assets and liabilities are recorded on these deferred tax assets and liabilities to the extent it is believed they will be recoverable from or refunded to customers in future rates.
Investment tax credits associated with rate regulated plant additions are deferred for financial statement purposes and amortized over the estimated useful lives of the related plant.

NW Holdings files consolidated or combined income tax returns that include NW Natural. Income tax expense is allocated on a separate company basis incorporating certain consolidated return considerations. Subsidiary income taxes payable or receivable are generally settled with NW Holdings, the common agent for income tax matters.

Interest and penalties related to unrecognized tax benefits, if any, are recognized within income tax expense and accrued interest and penalties are recognized within the related tax liability line in the consolidated balance sheets. No accrued interest or penalties for uncertain tax benefits have been recorded. See Note 11.

Environmental Contingencies
Loss contingencies are recorded as liabilities when it is probable a liability has been incurred and the amount of the loss is reasonably estimable in accordance with accounting standards for contingencies. Estimating probable losses requires an analysis of uncertainties that often depend upon judgments about potential actions by third parties. Accruals for loss contingencies are recorded based on an analysis of potential results.

With respect to environmental liabilities and related costs, estimates are developed based on a review of information available from numerous sources, including completed studies and site specific negotiations. NW Natural's policy is to accrue the full amount of such liability when information is sufficient to reasonably estimate the amount of probable liability. When information is not available to reasonably estimate the probable liability, or when only the range of probable liabilities can be estimated and no amount within the range is more likely than another, it is our policy to accrue at the low end of the range. Accordingly, due to numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, it may not be possible to reasonably estimate the high end of the range of possible loss. In those cases, the nature of the potential loss and the fact that the high end of the range cannot be reasonably estimated is disclosed. See Note 17.

Unconsolidated Affiliates
NW Holdings, NW Natural and NWN Water have equity interests in businesses which we account for under the equity method as we do not exercise control of the major operating and financial policies. The carrying value of these investments was $23.4 million and $14.5 million as of December 31, 2022 and 2021, respectively. The business transactions with our equity method investments are not significant. We regularly assesses the profitability and valuation of our investments for any potential impairment. See Note 13.

Cloud Computing Arrangements
Implementation costs associated with its cloud computing arrangements are capitalized consistent with costs capitalized for internal-use software. Capitalized implementation costs are included in other assets in the consolidated balance sheets. The implementation costs are amortized over the term of the related hosting agreement, including renewal periods that are reasonably certain to be exercised. Amortization expense of implementation costs are recorded as operations and maintenance expenses in the consolidated statements of comprehensive income. The implementation costs are included within operating activities in the consolidated statements of cash flows.

Subsequent Events
We monitor significant events occurring after the balance sheet date and prior to the issuance of the financial statements to determine the impacts, if any, of events on the financial statements to be issued.

3. EARNINGS PER SHARE

Basic earnings or loss per share are computed using NW Holdings' net income or loss and the weighted average number of common shares outstanding for each period presented. Diluted earnings per share are computed in the same manner, except using the weighted average number of common shares outstanding plus the effects of the assumed exercise of stock options and the payment of estimated stock awards from other stock-based compensation plans that are outstanding at the end of each period presented. Anti-dilutive stock awards are excluded from the calculation of diluted earnings or loss per common share.

NW Holdings' diluted earnings or loss per share are calculated as follows:

In thousands, except per share data	2022	2021	2020
Net income from continuing operations	$ 86,303	$ 78,666	$ 70,273
Income from discontinued operations, net of tax	—	—	6,508
Net income	$ 86,303	$ 78,666	$ 76,781
Average common shares outstanding - basic	33,934	30,702	30,541
Additional shares for stock-based compensation plans (See Note 8)	50	50	58
Average common shares outstanding - diluted	33,984	30,752	30,599
Earnings from continuing operations per share of common stock:			
Basic	$ 2.54	$ 2.56	$ 2.30
Diluted	2.54	2.56	2.30
Earnings from discontinued operations per share of common stock:			
Basic	$ —	$ —	$ 0.21
Diluted	—	—	0.21
Earnings per share of common stock:			
Basic	$ 2.54	$ 2.56	$ 2.51
Diluted	2.54	2.56	2.51
Additional information:			
Anti-dilutive shares	2	7	1

4. SEGMENT INFORMATION

We primarily operate in one reportable business segment, which is NW Natural's local gas distribution business and is referred to as the NGD segment. NW Natural and NW Holdings also have investments and business activities not specifically related to the NGD segment, which are aggregated and reported as other and described below for each entity.

No individual customer accounts for over 10% of NW Holdings' or NW Natural's operating revenues.

Natural Gas Distribution

NW Natural's local gas distribution segment (NGD) is a regulated utility principally engaged in the purchase, sale, and delivery of natural gas and related services to customers in Oregon and southwest Washington. The NGD business is responsible for building and maintaining a safe and reliable pipeline distribution system, purchasing sufficient gas supplies from producers and marketers, contracting for firm and interruptible transportation of gas over interstate pipelines to bring gas from the supply basins into its service territory, and re-selling the gas to customers subject to rates, terms, and conditions approved by the OPUC or WUTC. NGD also includes taking customer-owned gas and transporting it from interstate pipeline connections, or city gates, to the customers' end-use facilities for a fee, which is approved by the OPUC or WUTC. Approximately 88% of NGD customers are located in Oregon and 12% in Washington. On an annual basis, residential and commercial customers typically account for around 60% of total NGD volumes delivered and around 90% of NGD margin. Industrial customers largely account for the remaining volumes and NGD margin. A small amount of the margin is also derived from miscellaneous services, gains or losses from an incentive gas cost sharing mechanism, and other service fees.

Industrial sectors served by the NGD business include: pulp, paper, and other forest products; the manufacture of electronic, electrochemical and electrometallurgical products; the processing of farm and food products; the production of various mineral products; metal fabrication and casting; the production of machine tools, machinery, and textiles; the manufacture of asphalt, concrete, and rubber; printing and publishing; nurseries; and government and educational institutions.

In addition to NW Natural's local gas distribution business, the NGD segment also includes the portion of the Mist underground storage facility used to serve NGD customers, the North Mist gas storage expansion in Oregon, NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp, and NW Natural RNG Holding Company, LLC, a holding company established to invest in the development and procurement of regulated renewable natural gas for NW Natural.

NW Natural
NW Natural's activities in Other include Interstate Storage Services and third-party asset management services for the Mist facility in Oregon, appliance retail center operations, and corporate operating and non-operating revenues and expenses that cannot be allocated to NGD operations.

Earnings from Interstate Storage Services assets are primarily related to firm storage capacity revenues. Earnings from the Mist facility also include revenue, net of amounts shared with NGD customers, from management of NGD assets at Mist and upstream pipeline capacity when not needed to serve NGD customers. Under the Oregon sharing mechanism, NW Natural retains 80% of the pre-tax income from these services when the costs of the capacity were not included in NGD rates, or 10% of the pre-tax income when the costs have been included in these rates. The remaining 20% and 90%, respectively, are recorded to a deferred regulatory account for crediting back to NGD customers.

NW Holdings
NW Holdings' activities in Other include all remaining activities not associated with NW Natural, specifically NWN Water, which consolidates the water and wastewater utility operations and is pursuing other investments in the water and wastewater sector through itself and wholly-owned subsidiaries; NWN Water's equity investment in Avion Water Company, Inc.; NWN Gas Storage, a wholly-owned subsidiary of NWN Energy; NWN Energy's equity investment in Trail West Holdings, LLC (TWH) through August 6, 2020; other pipeline assets in NNG Financial; and NW Natural Renewables Holdings, LLC and its non-regulated renewable natural gas activities. For more information on the sale of TWH, see Note 13. Other also includes corporate revenues and expenses that cannot be allocated to other operations, including certain business development activities.

Segment Information Summary
Inter-segment transactions were immaterial for the periods presented. The following table presents summary financial information concerning the reportable segment and other for continuing operations. See Note 18 for information regarding discontinued operations for NW Holdings.

In thousands	NGD	Other (NW Natural)	NW Natural	Other (NW Holdings)	NW Holdings
2022					
Operating revenues	$ 989,752	$ 24,587	$ 1,014,339	$ 23,014	$ 1,037,353
Depreciation	111,871	1,086	112,957	3,750	116,707
Income (loss) from operations	152,839	16,535	169,374	(1,897)	167,477
Net income (loss) from continuing operations	79,690	11,874	91,564	(5,261)	86,303
Capital expenditures	315,979	2,707	318,686	19,916	338,602
Total assets at December 31, 2022	4,392,699	60,019	4,452,718	295,608	4,748,326
2021					
Operating revenues	$ 816,887	$ 26,170	$ 843,057	$ 17,343	$ 860,400
Depreciation	109,475	1,029	110,504	3,030	113,534
Income (loss) from operations	147,902	17,331	165,233	(2,116)	163,117
Net income (loss) from continuing operations	68,988	12,184	81,172	(2,506)	78,666
Capital expenditures	275,267	2,970	278,237	15,655	293,892
Total assets at December 31, 2021	3,846,112	52,260	3,898,372	166,232	4,064,604
2020					
Operating revenues	$ 741,072	$ 17,676	$ 758,748	$ 14,931	$ 773,679
Depreciation	100,591	995	101,586	2,097	103,683
Income (loss) from operations	137,724	9,916	147,640	711	148,351
Net income (loss) from continuing operations	63,555	7,008	70,563	(290)	70,273
Capital expenditures	263,777	2,271	266,048	6,968	273,016
Total assets at December 31, 2020	3,549,868	49,468	3,599,336	157,043	3,756,379

Natural Gas Distribution Margin
NGD margin is the primary financial measure used by the CODM, consisting of NGD operating revenues, reduced by the associated cost of gas, environmental remediation expense, and revenue taxes. The cost of gas purchased for NGD customers is generally a pass-through cost in the amount of revenues billed to regulated NGD customers. Environmental remediation expense represents collections received from customers through environmental recovery mechanisms in Oregon and Washington as well as adjustments for the Oregon environmental earnings test when applicable. This is offset by environmental remediation expense presented in operating expenses. Revenue taxes are collected from NGD customers and remitted to taxing authorities. The collections from customers are offset by the expense recognition of the obligation to the taxing authority. By subtracting cost of gas, environmental remediation expense, and revenue taxes from NGD operating revenues, NGD margin provides a key metric used by the CODM in assessing the performance of the NGD segment.

The following table presents additional segment information concerning NGD margin:

In thousands	2022	2021	2020
NGD margin calculation:			
NGD operating revenues	$ 970,124	$ 797,800	$ 721,950
Other regulated services	19,628	19,087	19,122
Total NGD operating revenues	989,752	816,887	741,072
Less: NGD cost of gas	429,861	292,538	262,980
Environmental remediation expense	12,389	9,938	9,691
Revenue taxes	41,627	34,600	30,291
NGD margin	$ 505,875	$ 479,811	$ 438,110

5. COMMON STOCK

As of December 31, 2022 and 2021, NW Holdings had 100 million shares of common stock authorized. As of December 31, 2022, NW Holdings had 319,777 shares reserved for issuance of common stock under the Employee Stock Purchase Plan (ESPP) and 394,102 shares reserved for issuance under the Dividend Reinvestment and Direct Stock Purchase Plan (DRPP). At NW Holdings' election, shares sold through the DRPP may be purchased in the open market or through original issuance of shares reserved for issuance under the DRPP.

In August 2021, NW Holdings initiated an at-the-market (ATM) equity program by entering into an equity distribution agreement under which NW Holdings may issue and sell from time to time shares of common stock, no par value, having an aggregate gross sales price of up to $200 million. NW Holdings is under no obligation to offer and sell common stock under the ATM equity program, which expires in August 2024. Any shares of common stock offered under the ATM equity program are registered on NW Holdings' universal shelf registration statement filed with the SEC. During the year ended December 31, 2022, NW Holdings issued and sold 1,381,728 shares of common stock pursuant to the ATM equity program resulting in cash proceeds of $69.7 million, net of fees and commissions paid to agents of $1.4 million. As of December 31, 2022, NW Holdings had $111.1 million of equity available for issuance under the program. The ATM equity program was initiated to raise funds for general corporate purposes, including equity contributions to NW Holdings' subsidiaries, NW Natural and NW Natural Water. Contributions to NW Natural and NW Natural Water will be used for general corporate purposes.

On April 1, 2022, NW Holdings issued and sold 2,875,000 shares of its common stock pursuant to a registration statement on Form S-3 and related prospectus settlement. NW Holdings received net offering proceeds, after deducting the underwriter's discounts and commissions and estimated expenses payable by NW Holdings, of approximately $138.6 million. The proceeds are to be used for general corporate purposes, including repayment of its short-term indebtedness and/or making equity contributions to NW Holdings' subsidiaries, NW Natural, NW Natural Water and NW Natural Renewables. Contributions to NW Natural, NW Natural Water and NW Natural Renewables are to be used for general corporate purposes. Of the contributions received by NW Natural, $130.0 million was used to repay its short-term indebtedness.

Stock Repurchase Program

NW Holdings has a share repurchase program under which it may purchase its common shares on the open market or through privately negotiated transactions. NW Holdings currently has Board authorization to repurchase up to an aggregate of the greater of 2.8 million shares or $100 million. No shares of common stock were repurchased pursuant to this program during the year ended December 31, 2022. Since the plan's inception in 2000 under NW Natural, a total of 2.1 million shares have been repurchased at a total cost of $83.3 million.

The following table summarizes the changes in the number of shares of NW Holdings' common stock issued and outstanding:

In thousands	Shares
Balance, December 31, 2019	30,472
Sales to employees under ESPP	3
Stock-based compensation	46
Sales to shareholders under DRPP	68
Balance, December 31, 2020	30,589
Sales to employees under ESPP	48
Stock-based compensation	49
Equity issuance	376
Sales to shareholders under DRPP	67
Balance, December 31, 2021	31,129
Sales to employees under ESPP	36
Stock-based compensation	42
Equity issuance	4,257
Sales to shareholders under DRPP	61
Balance, December 31, 2022	35,525

6. REVENUE

The following table presents disaggregated revenue from continuing operations:

	Year ended December 31, 2022				
In thousands	NGD	Other (NW Natural)	NW Natural	Other (NW Holdings)	NW Holdings
Natural gas sales	$ 989,654	$ —	$ 989,654	$ —	$ 989,654
Gas storage revenue, net	—	11,792	11,792	—	11,792
Asset management revenue, net	—	6,965	6,965	—	6,965
Appliance retail center revenue	—	5,830	5,830	—	5,830
Other revenue	2,510	—	2,510	23,014	25,524
Revenue from contracts with customers	992,164	24,587	1,016,751	23,014	1,039,765
Alternative revenue	(19,605)	—	(19,605)	—	(19,605)
Leasing revenue	17,193	—	17,193	—	17,193
Total operating revenues	$ 989,752	$ 24,587	$ 1,014,339	$ 23,014	$ 1,037,353

	Year ended December 31, 2021				
In thousands	NGD	Other (NW Natural)	NW Natural	Other (NW Holdings)	NW Holdings
Natural gas sales	$ 783,027	$ —	$ 783,027	$ —	$ 783,027
Gas storage revenue, net	—	10,830	10,830	—	10,830
Asset management revenue, net	—	9,387	9,387	—	9,387
Appliance retail center revenue	—	5,953	5,953	—	5,953
Other revenue	1,615	—	1,615	17,343	18,958
Revenue from contracts with customers	784,642	26,170	810,812	17,343	828,155
Alternative revenue	14,694	—	14,694	—	14,694
Leasing revenue	17,551	—	17,551	—	17,551
Total operating revenues	$ 816,887	$ 26,170	$ 843,057	$ 17,343	$ 860,400

In thousands	Year ended December 31, 2020 NGD	Other (NW Natural)	NW Natural	Other (NW Holdings)	NW Holdings
Natural gas sales	$ 710,422	$ —	$ 710,422	$ —	$ 710,422
Gas storage revenue, net	—	9,759	9,759	—	9,759
Asset management revenue, net	—	2,532	2,532	—	2,532
Appliance retail center revenue	—	5,385	5,385	—	5,385
Other revenue	1,337	—	1,337	14,931	16,268
Revenue from contracts with customers	711,759	17,676	729,435	14,931	744,366
Alternative revenue	10,870	—	10,870	—	10,870
Leasing revenue	18,443	—	18,443	—	18,443
Total operating revenues	$ 741,072	$ 17,676	$ 758,748	$ 14,931	$ 773,679

NW Natural's revenue represents substantially all of NW Holdings' revenue and is recognized for both registrants when the obligation to customers is satisfied and in the amount expected to be received in exchange for transferring goods or providing services. Revenue from contracts with customers contains one performance obligation that is generally satisfied over time, using the output method based on time elapsed, due to the continuous nature of the service provided. The transaction price is determined by a set price agreed upon in the contract or dependent on regulatory tariffs. Customer accounts are settled on a monthly basis or paid at time of sale and based on historical experience. It is probable that we will collect substantially all of the consideration to which we are entitled. We evaluated the probability of collection in accordance with the current expected credit losses standard.

NW Holdings and NW Natural do not have any material contract assets, as net accounts receivable and accrued unbilled revenue balances are unconditional and only involve the passage of time until such balances are billed and collected. NW Holdings and NW Natural do not have any material contract liabilities.

Revenue taxes are included in operating revenues with an equal and offsetting expense recognized in operating expenses in the consolidated statements of comprehensive income. Revenue-based taxes are primarily franchise taxes, which are collected from NGD customers and remitted to taxing authorities.

Natural Gas Distribution

Natural Gas Sales

NW Natural's primary source of revenue is providing natural gas to customers in the NGD service territory, which includes residential, commercial, industrial and transportation customers. NGD revenue is generally recognized over time upon delivery of the gas commodity or service to the customer, and the amount of consideration received and recognized as revenue is dependent on the Oregon and Washington tariffs. Customer accounts are to be paid in full each month, and there is no right of return or warranty for services provided. Revenues include firm and interruptible sales and transportation services, franchise taxes recovered from the customer, late payment fees, service fees, and accruals for gas delivered but not yet billed (accrued unbilled revenue). The accrued unbilled revenue balance is based on estimates of deliveries during the period from the last meter reading and management judgment is required for a number of factors used in this calculation, including customer use and weather factors.

We applied the significant financing practical expedient and have not adjusted the consideration NW Natural expects to receive from NGD customers for the effects of a significant financing component as all payment arrangements are settled annually. Due to the election of the right to invoice practical expedient, we do not disclose the value of unsatisfied performance obligations.

Alternative Revenue

Weather normalization (WARM) and decoupling mechanisms are considered to be alternative revenue programs. Alternative revenue programs are considered to be contracts between NW Natural and its regulator and are excluded from revenue from contracts with customers.

Leasing Revenue

Leasing revenue primarily consists of revenues from NW Natural's North Mist Storage contract with Portland General Electric (PGE) in support of PGE's gas-fired electric power generation facilities under an initial 30-year contract with options to extend, totaling up to an additional 50 years upon mutual agreement of the parties. The facility is accounted for as a sales-type lease with regulatory accounting deferral treatment. The investment is included in rate base under an established cost-of-service tariff schedule, with revenues recognized according to the tariff schedule and as such, profit upon commencement was deferred and will be amortized over the lease term. Leasing revenue also contains rental revenue from small leases of property owned by NW Natural to third parties. The majority of these transactions are accounted for as operating leases and the revenue is recognized over the term of the lease agreement. Lease revenue is excluded from revenue from contracts with customers. See Note 7 for additional information.

NW Natural Other

Gas Storage Revenue

NW Natural's other revenue includes gas storage activity, which includes Interstate Storage Services used to store natural gas for customers. Gas storage revenue is generally recognized over time as the gas storage service is provided to the customer and the amount of consideration received and recognized as revenue is dependent on set rates defined per the storage agreements. Noncash consideration in the form of dekatherms of natural gas is received as consideration for providing gas injection services to gas storage customers. This noncash consideration is measured at fair value using the average spot rate. Customer accounts are generally paid in full each month, and there is no right of return or warranty for services provided. Revenues include firm and interruptible storage services, net of the profit sharing amount refunded to NGD customers.

Asset Management Revenue

Revenues include the optimization of storage assets and pipeline capacity and are provided net of the profit sharing amount refunded to NGD customers. Certain asset management revenues received are recognized over time using a straight-line approach over the term of each contract, and the amount of consideration received and recognized as revenue is dependent on a variable pricing model. Variable revenues earned above guaranteed amounts are estimated and recognized at the end of each period using the most likely amount approach. Additionally, other asset management revenues may be based on a fixed rate. Generally, asset management accounts are settled on a monthly basis.

As of December 31, 2022, unrecognized revenue for the fixed component of the transaction price related to gas storage and asset management revenue was approximately $81.4 million. Of this amount, approximately $20.3 million will be recognized in 2023, $16.2 million in 2024, $13.5 million in 2025, $9.4 million in 2026, and $22.0 million thereafter. The amounts presented here are calculated using current contracted rates.

Appliance Retail Center Revenue

NW Natural owns and operates an appliance store that is open to the public, where customers can purchase natural gas home appliances. Revenue from the sale of appliances is recognized at the point in time in which the appliance is transferred to the third party responsible for delivery and installation services and when the customer has legal title to the appliance. It is required that the sale be paid for in full prior to transfer of legal title. The amount of consideration received and recognized as revenue varies with changes in marketing incentives and discounts offered to customers.

NW Holdings Other

NW Holdings' primary source of other revenue is providing water and wastewater services to customers. Water and wastewater service revenue is generally recognized over time upon delivery of the water commodity or service to the customer, and the amount of consideration received and recognized as revenue is dependent on the tariffs established in the state we operate. Customer accounts are to be paid in full each month, and there is no right of return or warranty for services provided.

We applied the significant financing practical expedient and have not adjusted the consideration we expect to receive from water distribution and wastewater collection customers for the effects of a significant financing component as all payment arrangements are settled annually. Due to the election of the right to invoice practical expedient, we do not disclose the value of unsatisfied performance obligations.

7. LEASES

Lease Revenue

Leasing revenue primarily consists of NW Natural's North Mist natural gas storage agreement with PGE which is billed under an OPUC-approved rate schedule and includes an initial 30-year term beginning May 2019 with options to extend, totaling up to an additional 50 years upon mutual agreement of the parties. Under U.S. GAAP, this agreement is classified as a sales-type lease and qualifies for regulatory accounting deferral treatment. The investment in the storage facility is included in rate base under a separately established cost-of-service tariff, with revenues recognized according to the tariff schedule. As such, the selling profit that was calculated upon commencement as part of the sale-type lease recognition was deferred and will be amortized over the lease term. Billing rates under the cost-of-service tariff will be updated annually to reflect current information including depreciable asset levels, forecasted operating expenses, and the results of regulatory proceedings, as applicable, and revenue received under this agreement is recognized as operating revenue on the consolidated statements of comprehensive income. There are no variable payments or residual value guarantees. The lease does not contain an option to purchase the underlying assets.

NW Natural also maintains a sales-type lease for specialized compressor facilities to provide high pressure compressed natural gas (CNG) services. Lease payments are outlined in an OPUC-approved rate schedule over a 10-year term. There are no variable payments or residual value guarantees. The selling profit computed upon lease commencement was not significant.

Our lessor portfolio also contains small leases of property owned by NW Natural to third parties. These transactions are accounted for as operating leases and the revenue is recognized over the term of the lease agreement.

The components of lease revenue at NW Natural were as follows:

	Year ended December 31,		
In thousands	2022	2021	2020
Lease revenue			
Operating leases	$ 74	$ 80	$ 88
Sales-type leases	17,119	17,471	18,355
Total lease revenue	$ 17,193	$ 17,551	$ 18,443

Additionally, lease revenue of $0.6 million, $0.5 million and $0.5 million was recognized for each of the years ended December 31, 2022, 2021, and 2020, respectively, related to operating leases associated with non-utility property rentals. Lease revenue related to these leases was presented in other income (expense), net on the consolidated statements of comprehensive income as it is non-operating income.

Total future minimum lease payments to be received under non-cancelable leases at December 31, 2022 are as follows:

In thousands	Operating	Sales-Type	Total
NW Natural:			
2023	$ 621	$ 16,557	$ 17,178
2024	612	15,867	16,479
2025	603	15,306	15,909
2026	36	14,901	14,937
2027	22	14,521	14,543
Thereafter	—	222,299	222,299
Total minimum lease payments	$ 1,894	$ 299,451	$ 301,345
Less: imputed interest		165,272	
Total leases receivable		$ 134,179	
Other NW Holdings:			
2023	$ 51	$ —	$ 51
2024	52	—	52
2025	53	—	53
2026	56	—	56
2027	57	—	57
Thereafter	857	—	857
Total minimum lease payments	$ 1,126	$ —	$ 1,126
NW Holdings:			
2023	$ 672	$ 16,557	$ 17,229
2024	664	15,867	16,531
2025	656	15,306	15,962
2026	92	14,901	14,993
2027	79	14,521	14,600
Thereafter	857	222,299	223,156
Total minimum lease payments	$ 3,020	$ 299,451	$ 302,471
Less: imputed interest		165,272	
Total leases receivable		$ 134,179	

The total leases receivable above is reported under the NGD segment and the short- and long-term portions are included within other current assets and assets under sales-type leases on the consolidated balance sheets, respectively. The total amount of unguaranteed residual assets was $5.1 million and $4.7 million at December 31, 2022 and 2021, respectively, and is included in assets under sales-type leases on the consolidated balance sheets. Additionally, under regulatory accounting, the revenues and expenses associated with these agreements are presented on the consolidated statements of comprehensive income such that their presentation aligns with similar regulated activities at NW Natural.

Lease Expense

Operating Leases

We have operating leases for land, buildings and equipment. Our primary lease is for NW Natural's headquarters and operations center. Our leases have remaining lease terms of nine months to 17 years. Many of our lease agreements include options to extend the lease, which we do not include in our minimum lease terms unless they are reasonably certain to be exercised. Short-term leases with a term of 12 months or less are not recorded on the balance sheet.

As most of our leases do not provide an implicit rate and are entered into by NW Natural, we use an estimated discount rate representing the rate we would have incurred to finance the funds necessary to purchase the leased asset and is based on information available at the lease commencement date in determining the present value of lease payments.

The components of lease expense, a portion of which is capitalized, were as follows:

	Year ended December 31, 2022		
In thousands	NW Natural	Other (NW Holdings)	NW Holdings
Operating lease expense	$ 7,003	$ 31	$ 7,034
Short-term lease expense	880	—	880

	Year ended December 31, 2021		
In thousands	NW Natural	Other (NW Holdings)	NW Holdings
Operating lease expense	$ 6,859	$ 58	$ 6,917
Short-term lease expense	1,220	—	1,220

	Year ended December 31, 2020		
In thousands	NW Natural	Other (NW Holdings)	NW Holdings
Operating lease expense	$ 4,381	$ 125	$ 4,506
Short-term lease expense	1,010	—	1,010

Supplemental balance sheet information related to operating leases as of December 31, 2022 is as follows:

In thousands	NW Natural	Other (NW Holdings)	NW Holdings
Operating lease right of use assets	$ 72,720	$ 709	$ 73,429
Operating lease liabilities - current liabilities	$ 1,363	$ 151	$ 1,514
Operating lease liabilities - non-current liabilities	78,345	620	78,965
Total operating lease liabilities	$ 79,708	$ 771	$ 80,479

Supplemental balance sheet information related to operating leases as of December 31, 2021 is as follows:

In thousands	NW Natural	Other (NW Holdings)	NW Holdings
Operating lease right of use assets	$ 74,987	$ 62	$ 75,049
Operating lease liabilities - current liabilities	$ 1,273	$ 23	$ 1,296
Operating lease liabilities - non-current liabilities	79,431	37	79,468
Total operating lease liabilities	$ 80,704	$ 60	$ 80,764

The weighted-average remaining lease terms and weighted-average discount rates for the operating leases at NW Natural were as follows:

	2022	2021
Weighted-average remaining lease term (years)	17.2	18.2
Weighted-average discount rate	7.3 %	7.2 %

Headquarters and Operations Center Lease
NW Natural commenced a 20-year operating lease agreement in March 2020 for a new headquarters and operations center in Portland, Oregon. There is an option to extend the term of the lease for two additional periods of seven years. There is a material timing difference between the minimum lease payments and expense recognition as calculated under operating lease accounting rules. OPUC issued an order allowing us to align our expense recognition with cash payments for ratemaking purposes. We recorded the difference between the minimum lease payments and the aggregate of the imputed interest on the finance lease

obligation and amortization of the right-of-use asset as a regulatory asset on our balance sheet. The balance of the regulatory asset was $6.9 million and $5.7 million as of December 31, 2022 and 2021, respectively.
Maturities of operating lease liabilities at December 31, 2022 were as follows:

In thousands	NW Natural	Other (NW Holdings)	NW Holdings
2023	$ 7,169	$ 195	$ 7,364
2024	7,299	196	7,495
2025	7,185	184	7,369
2026	7,353	140	7,493
2027	7,530	107	7,637
Thereafter	108,901	12	108,913
Total lease payments	145,437	834	146,271
Less: imputed interest	65,729	63	65,792
Total lease obligations	79,708	771	80,479
Less: current obligations	1,363	151	1,514
Long-term lease obligations	$ 78,345	$ 620	$ 78,965

As of December 31, 2022, there were no finance lease liabilities at NW Natural.

Cash Flow Information
Supplemental cash flow information related to leases was as follows:

	Year ended December 31, 2022		
In thousands	NW Natural	Other (NW Holdings)	NW Holdings
Cash paid for amounts included in the measurement of lease liabilities			
Operating cash flows from operating leases	$ 6,993	$ 64	$ 7,057
Finance cash flows from finance leases	524	—	524
Right of use assets obtained in exchange for lease obligations			
Operating leases	$ 309	$ 668	$ 977
Finance leases	270	—	270

	Year ended December 31, 2021		
In thousands	NW Natural	Other (NW Holdings)	NW Holdings
Cash paid for amounts included in the measurement of lease liabilities			
Operating cash flows from operating leases	$ 6,840	$ 58	$ 6,898
Finance cash flows from finance leases	801	—	801
Right of use assets obtained in exchange for lease obligations			
Operating leases	$ 223	$ —	$ 223
Finance leases	314	—	314

	Year ended December 31, 2020		
In thousands	NW Natural	Other (NW Holdings)	NW Holdings
Cash paid for amounts included in the measurement of lease liabilities			
Operating cash flows from operating leases	$ 4,466	$ 131	$ 4,597
Finance cash flows from finance leases	835	—	835
Right of use assets obtained in exchange for lease obligations			
Operating leases	$ 78,539	$ 51	$ 78,590
Finance leases	1,386	—	1,386

Finance Leases
NW Natural also leases building storage spaces for use as a gas meter room in order to provide natural gas to multifamily or mixed use developments. These contracts are accounted for as finance leases and typically involve a one-time upfront payment with no remaining liability. The right of use asset for finance leases was $2.3 million and $2.1 million at December 31, 2022 and 2021, respectively.

8. STOCK-BASED COMPENSATION

Stock-based compensation plans are designed to promote stock ownership in NW Holdings by employees and officers of NW Holdings and its affiliates. These compensation plans include a Long Term Incentive Plan (LTIP) and an ESPP.

Long Term Incentive Plan

The LTIP is intended to provide a flexible, competitive compensation program for eligible officers and key employees. Under the LTIP, shares of NW Holdings common stock are authorized for equity incentive grants in the form of stock, restricted stock, restricted stock units, stock options, or performance shares. An aggregate of 1,100,000 shares were authorized for issuance as of December 31, 2022. Shares awarded under the LTIP may be purchased on the open market or issued as original shares.

Of the 1,100,000 shares of common stock authorized for LTIP awards at December 31, 2022, there were 247,666 shares available for issuance under any type of award. This assumes market, performance, and service-based grants currently outstanding are awarded at the target level. There were no outstanding grants of restricted stock or stock options under the LTIP at December 31, 2022 or 2021. The LTIP stock awards are compensatory awards for which compensation expense is based on the fair value of stock awards, with expense being recognized over the performance and vesting period of the outstanding awards. Forfeitures are recognized as they occur.

Performance Shares

LTIP performance shares incorporate a combination of market, performance, and service-based factors. The following table summarizes performance share expense information:

Dollars in thousands	Shares[1]	Expense During Award Year[2]	Total Expense for Award
Estimated award:			
2020-2022 grant[3]	29,472	$ 888	$ 888
Actual award:			
2019-2021 grant	37,430	$ 1,323	$ 1,323
2018-2020 grant	31,600	$ 2,137	$ 2,137

(1) In addition to common stock shares, a participant also receives a dividend equivalent cash payment equal to the number of shares of common stock received on the award payout multiplied by the aggregate cash dividends paid per share during the performance period.
(2) Amount represents the expense recognized in the third year of the vesting period noted above. For the 2019-2021 and 2020-2022 grants, mutual understanding of the award's key terms was established in the third year of the vesting period, triggering full expense recognition in 2021 and 2022, respectively.
(3) This represents the estimated number of shares to be awarded as of December 31, 2022 as certain performance share measures have been achieved. Amounts are subject to change with final payout amounts authorized by the Board of Directors in February 2023.

The aggregate number of performance shares granted and outstanding at the target and maximum levels were as follows:

Dollars in thousands	Performance Share Awards Outstanding		2022
Performance Period	Target	Maximum	Expense
2020-22	31,160	62,320	$ 888
2021-23	—	—	—
2022-24	—	—	—
Total	31,160	62,320	$ 888

Performance share awards are based on the achievement of a three-year ROIC threshold that must be met and a cumulative EPS factor, which can be modified by a TSR factor relative to the performance of the Russell 2500 Utilities Index (2020-2022 performance share awards) or a specified peer group (2021-2023 and 2022-2024 performance share awards) over the three-year performance period. The performance period allows for one of the performance factors to remain variable until the first quarter of the third year of the award period. As the performance factor will not be approved until the first quarter of 2023 and 2024, there is not a mutual understanding of the awards' key terms and conditions between NW Natural and the participants as of December 31, 2022, and therefore, no expense was recognized for the 2021-2023 and 2022-2024 performance period. NW Natural will calculate the grant date fair value and recognize expense once the final performance factor has been approved. If the target is achieved for the 2021-2023 and 2022-2024 awards, NW Holdings would grant for accounting purposes 55,250 and 55,870 shares in the first quarter of 2023 and 2024, respectively.

Compensation expense is recognized in accordance with accounting standards for stock-based compensation and calculated based on performance levels achieved and an estimated fair value using the Monte-Carlo method. Due to there not being a mutual understanding of the 2021-2023 and 2022-2024 awards' key terms and conditions as noted above, the grant date fair value has not yet been determined and no non-vested shares existed at December 31, 2022. The weighted-average grant date fair value of non-vested shares associated with the 2020-2022 awards was $38.63 per share at December 31, 2022. The weighted-average grant date fair value of shares vested during the year was $38.63 per share and there were no performance shares granted during the year and no unrecognized compensation expense for accounting purposes as of December 31, 2022.

Restricted Stock Units

In 2012, RSUs began being granted under the LTIP instead of stock options under the Restated SOP. Generally, the RSUs awarded are forfeitable and include a performance-based threshold as well as a vesting period of four years from the grant date. The majority of our RSU grants obligate NW Holdings, upon vesting, to issue the RSU holder one share of common stock. The grant may also include a cash payment equal to the total amount of dividends paid per share between the grant date and vesting date of that portion of the RSU depending on the structure of the award agreement. The fair value of an RSU is equal to the closing market price of NW Holdings' common stock on the grant date. During 2022, total RSU expense was $2.1 million compared to $2.0 million in 2021 and $2.0 million in 2020. As of December 31, 2022, there was $3.5 million of unrecognized compensation cost from grants of RSUs, which is expected to be recognized over a period extending through 2026.

Information regarding the RSU activity is summarized as follows:

	Number of RSUs	Weighted - Average Price Per RSU
Nonvested, December 31, 2019	79,733	$ 61.17
Granted	33,594	55.58
Vested	(29,273)	59.29
Forfeited	(1,590)	69.71
Nonvested, December 31, 2020	82,464	59.40
Granted	38,160	49.16
Vested	(31,733)	60.06
Forfeited	(1,164)	46.82
Nonvested, December 31, 2021	87,727	54.87
Granted	48,212	46.50
Vested	(33,054)	55.90
Forfeited	(3,037)	56.34
Nonvested, December 31, 2022	99,848	$ 50.44

Employee Stock Purchase Plan

NW Holdings' ESPP allows employees of NW Holdings, NW Natural and certain designated subsidiaries to purchase common stock at 85% of the closing price on the trading day immediately preceding the initial offering date, which is set annually. For the 2022-2023 ESPP period, each eligible employee may purchase up to $21,223 worth of stock through payroll deductions over a period defined by the Board of Directors, with shares issued at the end of the subscription period.

Stock-Based Compensation Expense

Stock-based compensation expense is recognized as operations and maintenance expense or is capitalized as part of construction overhead at the entity at which the award recipient is employed. The following table summarizes the NW Holdings' financial statement impact, substantially all of which was recorded at NW Natural, of stock-based compensation under the LTIP and ESPP:

In thousands	2022	2021	2020
Operations and maintenance expense, for stock-based compensation	$ 2,877	$ 3,272	$ 3,525
Income tax benefit	(762)	(866)	(933)
Net stock-based compensation effect on net income	2,115	2,406	2,592
Amounts capitalized for stock-based compensation	$ 351	$ 344	$ 841

9. DEBT

Short-Term Debt
The primary source of short-term liquidity for NW Holdings is cash balances, dividends from its operating subsidiaries, in particular NW Natural, available cash from a multi-year credit facility, and short-term credit facilities it may enter into from time to time.

The primary source of short-term liquidity for NW Natural is from the sale of commercial paper, available cash from a multi-year credit facility, and short-term credit facilities it may enter into from time to time. In addition to issuing commercial paper or entering into bank loans to meet working capital requirements, including seasonal requirements to finance gas purchases and accounts receivable, short-term debt may also be used to temporarily fund capital requirements. For NW Natural, commercial paper and bank loans are periodically refinanced through the sale of long-term debt or equity contributions from NW Holdings. Commercial paper, when outstanding, is sold through two commercial banks under an issuing and paying agency agreement and is supported by one or more unsecured revolving credit facilities. See "*Credit Agreements*" below.

At December 31, 2022 and 2021, NW Natural's short-term debt consisted of the following:

	December 31, 2022		December 31, 2021	
In millions	Balance Outstanding	Weighted Average Interest Rate[1]	Balance Outstanding	Weighted Average Interest Rate[1]
NW Natural:				
Commercial paper	$ 170.2	4.6 %	$ 245.5	0.3 %
Other (NW Holdings):				
Credit agreement	88.0	5.3 %	144.0	1.1 %
NW Holdings	$ 258.2		$ 389.5	

[1] Weighted average interest rate on outstanding short-term debt

The carrying cost of commercial paper approximates fair value using Level 2 inputs. See Note 2 for a description of the fair value hierarchy. At December 31, 2022, NW Natural's commercial paper had a maximum remaining maturity of 6 days and an average remaining maturity of 5 days.

Credit Agreements
NW Holdings
In November 2021, NW Holdings entered into an amended and restated $200.0 million credit agreement, with a feature that allows NW Holdings to request increases in the total commitment amount, up to a maximum of $300.0 million. The maturity date of the agreement is November 3, 2026, with an available extension of commitments for two additional one-year periods, subject to lender approval. Interest charges on the NW Holdings credit agreement were indexed to the London Interbank Offered Rate (LIBOR) through January 31, 2023. The agreement was amended to replace LIBOR with the secured overnight financing rate (SOFR) beginning February 2023. The SOFR is subject to a 10 basis point spread adjustment.

The NW Holdings credit agreement permits the issuance of letters of credit in an aggregate amount of up to $40.0 million. The principal amount of borrowings under the credit agreement is due and payable on the maturity date. The credit agreement requires NW Holdings to maintain a consolidated indebtedness to total capitalization ratio of 70% or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. NW Holdings was in compliance with this covenant at December 31, 2022 and 2021.

The NW Holdings credit agreement also requires NW Holdings to maintain debt ratings (which are defined by a formula using NW Natural's credit ratings in the event NW Holdings does not have a credit rating) with Standard & Poor's (S&P) and Moody's Investors Service, Inc. (Moody's) and notify the lenders of any change in its senior unsecured debt ratings or senior secured debt ratings, as applicable, by such rating agencies. A change in NW Holdings' debt ratings by S&P or Moody's is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit agreement. Rather, interest rates on any loans outstanding under the credit agreements are tied to debt ratings and therefore, a change in the debt rating would increase or decrease the cost of any loans under the credit agreements when ratings are changed. NW Holdings does not currently maintain ratings with S&P or Moody's.

There was $88.0 million and $144.0 million of outstanding balances under the NW Holdings agreement at December 31, 2022 and 2021, respectively. No letters of credit were issued or outstanding under the NW Holdings agreement at December 31, 2022 and 2021.

NW Natural
In November 2021, NW Natural entered into an amended and restated credit agreement for unsecured revolving loans totaling $400.0 million, with a feature that allows NW Natural to request increases in the total commitment amount, up to a maximum of $600.0 million. The maturity date of the agreement is November 3, 2026 with an available extension of commitments for two additional one-year periods, subject to lender approval. The credit agreement permits the issuance of letters of credit in an

aggregate amount of up to $60.0 million. The principal amount of borrowings under the credit agreement is due and payable on the maturity date. Interest charges on the NW Natural credit agreement were indexed to the LIBOR through January 31, 2023. The agreement was amended to replace LIBOR with the SOFR beginning February 2023. The SOFR is subject to a 10 basis point spread adjustment.

NW Natural's credit agreement requires NW Natural to maintain a consolidated indebtedness to total capitalization ratio of 70% or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. NW Natural was in compliance with this covenant at December 31, 2022 and 2021.

The NW Natural credit agreement also requires NW Natural to maintain credit ratings with S&P and Moody's and notify the lenders of any change in NW Natural's senior unsecured debt ratings or senior secured debt ratings, as applicable, by such rating agencies. A change in NW Natural's debt ratings by S&P or Moody's is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit agreement. Rather, interest rates on any loans outstanding under the credit agreement are tied to debt ratings and therefore, a change in the debt rating would increase or decrease the cost of any loans under the credit agreement when ratings are changed.

There were no outstanding balances under NW Natural's credit agreement and no letters of credit issued or outstanding at December 31, 2022 and 2021. In February 2023, NW Natural issued a $14 million letter of credit through its existing credit agreement. There were no other letters of credit outstanding under the credit agreement.

Long-Term Debt

NW Holdings

At December 31, 2022 and 2021, NW Holdings long-term debt consisted of the following:

	December 31, 2022		December 31, 2021	
In millions	Balance Outstanding	Weighted Average Interest Rate[1]	Balance Outstanding	Weighted Average Interest Rate[1]
NW Natural first mortgage bonds	$ 1,134.7	4.5 %	$ 994.7	4.4 %
NW Holdings credit agreement	100.0	4.2 %	—	— %
NWN Water credit agreement	50.0	4.2 %	—	— %
NWN Water term loan	55.0	2.5 %	55.0	0.8 %
Other long-term debt	6.2		3.5	
Long-term debt, gross	$ 1,345.9		$ 1,053.2	
Less: unamortized debt issuance costs	9.0		8.3	
Less: current maturities	90.7		0.3	
Total long-term debt	$ 1,246.2		$ 1,044.6	

(1) Weighted average interest rate for the years ended December 31, 2022 and 2021.

Long-term debt at NWN Water is primarily comprised of a five-year term loan agreement for $55.0 million, due in 2026. NWN Water entered into this agreement in June 2021 and the interest rate is based upon the one-month SOFR rate. The loan is guaranteed by NW Holdings and requires NW Holdings to maintain a consolidated indebtedness to total capitalization ratio of 70% or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. NW Holdings was in compliance with this covenant at December 31, 2022 and 2021, with a consolidated indebtedness to total capitalization ratio of 57.6% and 60.5%, respectively. In December 2022, NW Holdings entered into a swap to fix the interest rate on this debt beginning in January 2023 through the loan's maturity. See "Interest Rate Swap Agreements" below for more detail.

In September 2022, NW Holdings entered into an 18-month credit agreement for $100.0 million and borrowed the full amount. The interest rate is based on the SOFR. The loan is due and payable on March 15, 2024. The credit agreement prohibits NW Holdings from permitting consolidated indebtedness to be greater than 70% of total capitalization, each as defined therein and calculated as of the end of each fiscal quarter. Failure to comply with this financial covenant would entitle the lenders to accelerate the maturity of the amounts outstanding under the credit agreement. NW Holdings was in compliance with this financial covenant as of December 31, 2022. In December 2022, NW Holdings entered into a swap to fix the interest rate on this debt beginning in January 2023 through the loan's maturity. See "Interest Rate Swap Agreements" below for more detail.

In September 2022, NWN Water entered into an 18-month credit agreement for $50.0 million and borrowed the full amount. The interest rate is based on the SOFR. The loan is due and payable on March 15, 2024. The credit agreement prohibits NWN Water and NW Holdings from permitting consolidated indebtedness to be greater than 70% of total capitalization, each as defined therein and calculated as of the end of each fiscal quarter. Failure to comply with this financial covenant would entitle the lenders to accelerate the maturity of the amounts outstanding under the credit agreement. NWN Water and NW Holdings were in compliance with this financial covenant as of December 31, 2022.

Interest Rate Swap Agreements

NW Holdings and NWN Water entered into interest rate swap agreements with major financial institutions that effectively convert variable-rate debt to a fixed rate. Interest payments made between the effective date and expiration date are hedged by the swap agreements. The notional amount, effective date, expiration date and rate of the swap agreements are shown in the table below:

In millions	Notional Amount	Effective Date	Expiration Date	Fixed Rate
NW Holdings	$ 100.0	1/17/2023	3/15/2024	4.7 %
NWN Water	$ 55.0	1/19/2023	6/10/2026	3.8 %

NW Natural

NW Natural's issuance of First Mortgage Bonds (FMBs), which includes NW Natural's medium-term notes, under the Mortgage and Deed of Trust (Mortgage) is limited by eligible property, adjusted net earnings, and other provisions of the Mortgage. The Mortgage constitutes a first mortgage lien on certain gas properties owned from time to time by NW Natural, including substantially all of NW Natural's NGD property.

In July 2022, NW Natural entered into a Bond Purchase Agreement between NW Natural and the institutional investors named as purchasers therein (the Bond Purchase Agreement). The Bond Purchase Agreement provides for the issuance of $140.0 million aggregate principal amount of NW Natural's FMBs due in 2052 (the Bonds). The Bonds were issued on September 30, 2022. The Bonds bear interest at the rate of 4.78% per annum, payable semi-annually on March 30 and September 30 of each year, commencing March 30, 2023, and will mature on September 30, 2052. The Bonds are subject to redemption prior to maturity at the option of NW Natural, in whole or in part, (i) at any time prior to March 30, 2052, at a redemption price equal to 100% of the principal amount thereof plus a "make-whole" premium and accrued and unpaid interest thereon to the date of redemption, and (ii) at any time on and after March 30, 2052, at 100% of the principal amount thereof plus accrued and unpaid interest thereon to the date of redemption.

Maturities and Outstanding Long-Term Debt

Retirement of long-term debt for each of the annual periods through December 31, 2027 and thereafter are as follows:

In thousands	Long-term debt maturities
NW Natural:	
2023	$ 90,000
2024	—
2025	30,000
2026	55,000
2027	64,700
Thereafter	895,000
Total	$ 1,134,700

The following table presents debt outstanding as of December 31:

In thousands	2022	2021
NW Natural:		
First Mortgage Bonds:		
3.542% Series due 2023	50,000	50,000
5.620% Series due 2023	40,000	40,000
7.720% Series due 2025	20,000	20,000
6.520% Series due 2025	10,000	10,000
7.050% Series due 2026	20,000	20,000
3.211% Series due 2026	35,000	35,000
7.000% Series due 2027	20,000	20,000
2.822% Series due 2027	25,000	25,000
6.650% Series due 2027	19,700	19,700
6.650% Series due 2028	10,000	10,000
3.141% Series due 2029	50,000	50,000
7.740% Series due 2030	20,000	20,000
7.850% Series due 2030	10,000	10,000
5.820% Series due 2032	30,000	30,000
5.660% Series due 2033	40,000	40,000
5.250% Series due 2035	10,000	10,000
4.000% Series due 2042	50,000	50,000
4.136% Series due 2046	40,000	40,000
3.685% Series due 2047	75,000	75,000
4.110% Series due 2048	50,000	50,000
3.869% Series due 2049	90,000	90,000
3.600% Series due 2050	150,000	150,000
3.078% Series due 2051	130,000	130,000
4.780% Series due 2052	140,000	—
Long-term debt, gross	1,134,700	994,700
Less: current maturities	90,000	—
Total long-term debt	$ 1,044,700	$ 994,700

Fair Value of Long-Term Debt

NW Holdings' and NW Natural's outstanding debt does not trade in active markets. The fair value of debt is estimated using the value of outstanding debt at natural gas distribution companies with similar credit ratings, terms, and remaining maturities to NW Holdings' and NW Natural's debt that actively trade in public markets. Substantially all outstanding debt at NW Holdings is comprised of NW Natural debt. These valuations are based on Level 2 inputs as defined in the fair value hierarchy. See Note 2.

The following table provides an estimate of the fair value of long-term debt, including current maturities of long-term debt, using market prices in effect on the valuation date:

	December 31,	
In thousands	2022	2021
NW Natural:		
Gross long-term debt	$ 1,134,700	$ 994,700
Unamortized debt issuance costs	(8,823)	(8,205)
Carrying amount	$ 1,125,877	$ 986,495
Estimated fair value[(1)]	$ 944,383	$ 1,110,741
NW Holdings:		
Gross long-term debt	$ 1,345,851	$ 1,053,241
Unamortized debt issuance costs	(8,987)	(8,309)
Carrying amount	$ 1,336,864	$ 1,044,932
Estimated fair value[(1)]	$ 1,148,395	$ 1,174,500

[(1)] Estimated fair value does not include unamortized debt issuance costs.

10. PENSION AND OTHER POSTRETIREMENT BENEFIT COSTS

NW Natural maintains a qualified non-contributory defined benefit pension plan (Pension Plan) for all eligible employees, non-qualified supplemental pension plans for eligible executive officers and other key employees, and other postretirement employee benefit plans. NW Natural also has a qualified defined contribution plan (Retirement K Savings Plan) for all eligible employees. The Pension Plan and Retirement K Savings Plan have plan assets, which are held in qualified trusts to fund retirement benefits.
Effective January 1, 2007 and 2010, the Pension Plan and postretirement benefits for non-union employees and union employees, respectively, were closed to new participants. Non-union and union employees hired or re-hired after December 31, 2006 and 2009, respectively, and employees of NW Natural subsidiaries are provided an enhanced Retirement K Savings Plan benefit.

The following table provides a reconciliation of the changes in NW Natural's benefit obligations and fair value of plan assets, as applicable, for NW Natural's pension and other postretirement benefit plans, excluding the Retirement K Savings Plan, and a summary of the funded status and amounts recognized in NW Holdings' and NW Natural's consolidated balance sheets as of December 31:

	Postretirement Benefit Plans			
	Pension Benefits		Other Benefits	
In thousands	2022	2021	2022	2021
Reconciliation of change in benefit obligation:				
Obligation at January 1	$ 542,618	$ 566,147	$ 27,223	$ 29,039
Service cost	5,933	6,982	193	238
Interest cost	14,593	13,447	724	684
Net actuarial gain	(122,168)	(18,587)	(6,234)	(688)
Benefits paid	(27,563)	(25,371)	(2,026)	(2,050)
Obligation at December 31	$ 413,413	$ 542,618	$ 19,880	$ 27,223
Reconciliation of change in plan assets:				
Fair value of plan assets at January 1	$ 399,217	$ 373,932	$ —	$ —
Actual return on plan assets	(93,703)	38,712	—	—
Employer contributions	2,353	11,944	2,026	2,050
Benefits paid	(27,563)	(25,371)	(2,026)	(2,050)
Fair value of plan assets at December 31	$ 280,304	$ 399,217	$ —	$ —
Funded status at December 31	$ (133,109)	$ (143,401)	$ (19,880)	$ (27,223)

At December 31, 2022, the net liability (benefit obligations less market value of plan assets) for the Pension Plan decreased $3.3 million compared to 2021. The decrease in the net pension liability is primarily due to the $118.9 million decrease in plan assets and the $122.3 million decrease to the pension benefit obligation. The liability for non-qualified plans decreased $6.9 million, and the liability for other postretirement benefits decreased $7.3 million in 2022.

NW Natural's Pension Plan had a projected benefit obligation of $381.6 million and $503.9 million at December 31, 2022 and 2021, respectively, and fair values of plan assets of $280.3 million and $399.2 million, respectively. The plan had an accumulated benefit obligation of $353.4 million and $464.4 million at December 31, 2022 and 2021, respectively.

The following table presents amounts realized through regulatory assets or in other comprehensive loss (income) for the years ended December 31:

	Regulatory Assets						Other Comprehensive Loss (Income)		
	Pension Benefits			Other Postretirement Benefits			Pension Benefits		
In thousands	2022	2021	2020	2022	2021	2020	2022	2021	2020
Net actuarial (gain) loss	$ 2,833	$ (32,258)	$ 16,170	$ (6,234)	$ (688)	$ 145	$ (5,706)	$ (812)	$ 3,873
Amortization of:									
Prior service credit	—	—	—	333	468	468	—	—	—
Actuarial loss	(11,531)	(21,250)	(18,627)	(426)	(645)	(607)	(1,081)	(1,225)	(923)
Total	$ (8,698)	$ (53,508)	$ (2,457)	$ (6,327)	$ (865)	$ 6	$ (6,787)	$ (2,037)	$ 2,950

The following table presents amounts recognized in regulatory assets and accumulated other comprehensive loss (AOCL) at December 31:

	Regulatory Assets				AOCL	
	Pension Benefits		Other Postretirement Benefits		Pension Benefits	
In thousands	2022	2021	2022	2021	2022	2021
Prior service credit	$ —	$ —	$ —	$ (333)	$ —	$ —
Net actuarial loss (gain)	102,240	112,182	(826)	5,834	8,717	15,399
Total	$ 102,240	$ 112,182	$ (826)	$ 5,501	$ 8,717	$ 15,399

The following table presents amounts recognized by NW Holdings and NW Natural in AOCL and the changes in AOCL related to NW Natural's non-qualified employee benefit plans:

	Year ended December 31,	
In thousands	2022	2021
Beginning balance	$ (11,404)	$ (12,902)
Amounts reclassified to AOCL	5,706	812
Amounts reclassified from AOCL:		
Amortization of actuarial losses	1,081	1,225
Total reclassifications before tax	6,787	2,037
Tax benefit	(1,797)	(539)
Total reclassifications for the period	4,990	1,498
Ending balance	$ (6,414)	$ (11,404)

In 2023, NW Natural will not amortize any estimated costs from regulatory assets to net periodic benefit costs.

The assumed discount rates for NW Natural's Pension Plan and other postretirement benefit plans were determined independently based on the FTSE Above Median Curve (discount rate curve), which uses high quality corporate bonds rated AA- or higher by S&P or Aa3 or higher by Moody's. The discount rate curve was applied to match the estimated cash flows in each of the plans to reflect the timing and amount of expected future benefit payments for these plans.

The assumed expected long-term rate of return on plan assets for the Pension Plan was developed using a weighted-average of the expected returns for the target asset portfolio. In developing the expected long-term rate of return assumption, consideration was given to the historical performance of each asset class in which the plan's assets are invested and the target asset allocation for plan assets.

The investment strategy and policies for Pension Plan assets held in the retirement trust fund were approved by the NW Natural Retirement Committee, which is composed of senior management with the assistance of an outside investment consultant. The policies set forth the guidelines and objectives governing the investment of plan assets. Plan assets are invested for total return with appropriate consideration for liquidity, portfolio risk, and return expectations. All investments are expected to satisfy the prudent investments rule under the Employee Retirement Income Security Act of 1974. The approved asset classes may include cash and short-term investments, fixed income, common stock and convertible securities, absolute and real return strategies, and real estate. Plan assets may be invested in separately managed accounts or in commingled or mutual funds. Investment re-balancing takes place periodically as needed, or when significant cash flows occur, in order to maintain the allocation of assets within the stated target ranges. The retirement trust fund for the Pension Plan is not currently invested in NW Holdings or NW Natural securities.

The following table presents the Pension Plan asset target allocation at December 31, 2022:

Asset Category	Target Allocation
Long government/credit	20 %
U.S. large cap equity	18
Non-U.S. equity	18
Absolute return strategies	12
U.S. small/mid cap equity	10
Real estate funds	7
High yield bonds	5
Emerging markets equity	5
Emerging market debt	5

Non-qualified supplemental defined benefit plan obligations were $31.8 million and $38.7 million at December 31, 2022 and 2021, respectively. These plans are not subject to regulatory deferral, and the changes in actuarial gains and losses, prior service costs, and transition assets or obligations are recognized in AOCL, net of tax until they are amortized as a component of net periodic benefit cost. These are unfunded, non-qualified plans with no plan assets; however, a significant portion of the obligations is indirectly funded with company and trust-owned life insurance and other assets.

Other postretirement benefit plans are unfunded plans but are subject to regulatory deferral. The actuarial gains and losses, prior service costs, and transition assets or obligations for these plans are recognized as a regulatory asset.

Net periodic benefit costs consist of service costs, interest costs, the expected returns on plan assets, and the amortization of gains and losses and prior service costs. The gains and losses are the sum of the actuarial and asset gains and losses throughout the year and are amortized over the average remaining service period of active participants. The asset gains and losses are based in part on a market-related valuation of assets. The market-related valuation reflects differences between expected returns and actual investment returns with the differences recognized over a two-year period from the year in which they occur, thereby reducing year-to-year net periodic benefit cost volatility.

The service cost component of net periodic benefit cost for NW Natural pension and other postretirement benefit plans is recognized in operations and maintenance expense in the consolidated statements of comprehensive income. The other non-service cost components are recognized in other income (expense), net in the consolidated statements of comprehensive income. The following table provides the components of net periodic benefit cost for NW Natural's pension and other postretirement benefit plans for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
In thousands	2022	2021	2020	2022	2021	2020
Service cost	$ 5,933	$ 6,981	$ 6,614	$ 193	$ 238	$ 258
Interest cost	14,593	13,448	16,161	724	684	905
Expected return on plan assets	(25,698)	(24,232)	(21,865)	—	—	—
Amortization of prior service credit	—	—	—	(333)	(468)	(468)
Amortization of net actuarial loss	12,612	22,475	19,550	426	645	607
Net periodic benefit cost	7,440	18,672	20,460	1,010	1,099	1,302
Amount allocated to construction	(2,621)	(3,015)	(2,798)	(76)	(93)	(98)
Net periodic benefit cost charged to expense	4,819	15,657	17,662	934	1,006	1,204
Amortization of regulatory balancing account	7,131	7,131	7,131	—	—	—
Net amount charged to expense	$ 11,950	$ 22,788	$ 24,793	$ 934	$ 1,006	$ 1,204

Net periodic benefit costs are reduced by amounts capitalized to NGD plant. In addition, a certain amount of net periodic benefit costs were recorded to the regulatory balancing account, representing net periodic pension expense for the Pension Plan above the amount set in rates, as approved by the OPUC, from 2011 through October 31, 2018. Total amortization of the regulatory balancing account of $7.1 million was recognized in each of the years ended December 31, 2022 and 2021, of which $2.6 million was charged to operations and maintenance expense and $4.5 million was charged to other income (expense).

The following table provides the assumptions used in measuring periodic benefit costs and benefit obligations for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
	2022	2021	2020	2022	2021	2020
Assumptions for net periodic benefit cost:						
Weighted-average discount rate	2.71 %	2.40 %	3.18 %	2.72 %	2.34 %	3.11 %
Rate of increase in compensation	3.50 %	3.50 %	3.50 %	n/a	n/a	n/a
Expected long-term rate of return	7.00 %	7.25 %	7.25 %	n/a	n/a	n/a
Assumptions for year-end funded status:						
Weighted-average discount rate	5.18 %	2.71 %	2.36 %	5.19 %	2.72 %	2.34 %
Rate of increase in compensation[1]	4.00-6.00%	3.50 %	3.50-6.50%	n/a	n/a	n/a
Expected long-term rate of return	7.50 %	7.00 %	7.25 %	n/a	n/a	n/a

[1] Rate assumption ranges from 4.5% to 5.0% in 2023, 4.0% to 6.0% in 2024 and 4.0% thereafter.

The assumed annual increase in health care cost trend rates used in measuring other postretirement benefits as of December 31, 2022 was 7.00%. These trend rates apply to both medical and prescription drugs. Medical costs and prescription drugs are assumed to decrease gradually each year to a rate of 4.00% by 2029.

Assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans; however, other postretirement benefit plans have a cap on the amount of costs reimbursable by NW Natural.
Mortality assumptions are reviewed annually and are updated for material changes as necessary. In 2022, mortality rate assumptions remained consistent with 2021, using Pri-2012 mortality tables using scale MP-2021.

The following table provides information regarding employer contributions and benefit payments for NW Natural's Pension Plan, non-qualified pension plans, and other postretirement benefit plans for the years ended December 31, and estimated future contributions and payments:

In thousands	Pension Benefits	Other Benefits
Employer Contributions:		
2021	$ 11,944	$ 2,050
2022	2,353	2,026
2023 (estimated)	2,333	1,586
Benefit Payments:		
2020	25,073	1,837
2021	25,371	2,050
2022	27,563	2,026
Estimated Future Benefit Payments:		
2023	26,499	1,586
2024	27,029	1,591
2025	27,541	1,586
2026	27,981	1,560
2027	36,485	1,552
2028-2032	145,486	7,345

Employer Contributions to Company-Sponsored Defined Benefit Pension Plan
NW Natural makes contributions to its Pension Plan based on actuarial assumptions and estimates, tax regulations, and funding requirements under federal law. The Pension Plan was underfunded by $101.3 million at December 31, 2022. NW Natural made no cash contributions to its Pension Plan for 2022. The American Rescue Plan, which was signed into law on March 11, 2021, includes a provision for pension relief that extends the amortization period for required contributions from 7 to 15 years and provides for the stabilization of interest rates used to calculate future required contributions. As a result, NW Natural does not expect to make any plan contributions during 2023.

Multiemployer Pension Plan
In addition to the NW Natural-sponsored Pension Plan presented above, prior to 2014 NW Natural contributed to a multiemployer pension plan for its NGD union employees known as the Western States Office and Professional Employees International Union Pension Fund (Western States Plan). That plan's employer identification number is 94-6076144. Effective December 22, 2013, NW Natural withdrew from the plan, which was a noncash transaction. Vested participants will receive all benefits accrued through the date of withdrawal. As the plan was underfunded at the time of withdrawal, NW Natural was assessed a withdrawal liability of $8.3 million, plus interest, which requires NW Natural to pay $0.6 million each year to the plan for 20 years beginning in July 2014. The cost of the withdrawal liability was deferred to a regulatory account on the balance sheet.

Payments were $0.6 million for 2022, and as of December 31, 2022, the liability balance was $5.4 million. For 2021 and 2020, contributions to the plan were $0.4 million and $0.7 million, respectively, which was approximately 3% to 5% of the total contributions to the plan by all employer participants in those years.

Defined Contribution Plan
NW Natural's Retirement K Savings Plan is a qualified defined contribution plan under Internal Revenue Code Sections 401(a) and 401(k). NW Natural contributions totaled $9.6 million, $8.8 million, and $8.3 million for 2022, 2021, and 2020, respectively.

Deferred Compensation Plans
NW Natural's supplemental deferred compensation plans for eligible officers and senior managers are non-qualified plans. These plans are designed to enhance the retirement savings of employees and to assist them in strengthening their financial security by providing an incentive to save and invest regularly.

Fair Value
Below is a description of the valuation methodologies used for assets measured at fair value. In cases where NW Natural's Pension Plan is invested through a collective trust fund or mutual fund, the fund's market value is utilized. Market values for investments directly owned are also utilized.

U.S. EQUITY. These are non-published net asset value (NAV) assets. The non-published NAV assets consist of commingled trusts where NAV is not published but the investment can be readily disposed of at NAV or market value. The underlying investments in this asset class includes investments primarily in U.S. common stocks.

INTERNATIONAL/GLOBAL EQUITY. These are Level 1 and non-published NAV assets. The Level 1 asset is a mutual fund, and the non-published NAV assets consist of commingled trusts where the NAV/unit price is not published, but the investment can be readily disposed of at the NAV/unit price. The mutual funds has a readily determinable fair value, including a published NAV, and the commingled trusts are valued at unit price. This asset class includes investments primarily in foreign equity common stocks.

LIABILITY HEDGING. These are non-published NAV assets. The non-published NAV assets consist of commingled trusts where NAV is not published but the investment can be readily disposed of at NAV or market value. The underlying investments in this asset class include long duration fixed income investments primarily in U.S. treasuries, U.S. government agencies, municipal securities, mortgage-backed securities, asset-backed securities, as well as U.S. and international investment-grade corporate bonds.

OPPORTUNISTIC. These are non-published NAV assets. The non-published NAV assets consist of commingled trusts where NAV is not published but the investment can be readily disposed of at NAV or market value. The underlying investments in this asset class include real estate investment trust equities, high yield bonds, floating rate debt, emerging market debt and a commodity index pool.

CASH AND CASH EQUIVALENTS. These are Level 1 and non-published NAV assets. The Level 1 assets consist of cash in U.S. dollars, which can be readily disposed of at face value. The non-published NAV assets represent mutual funds without published NAV's but the investment can be readily disposed of at the NAV. The mutual funds are valued at the NAV of the shares held by the plan at the valuation date.

The preceding valuation methods may produce a fair value calculation that is not indicative of net realizable value or reflective of future fair values. Although we believe these valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain investments could result in a different fair value measurement at the reporting date.

Investment securities are exposed to various financial risks including interest rate, market, and credit risks. Due to the level of risk associated with certain investment securities, it is reasonably possible that changes in the values of NW Natural's investment securities will occur in the near term and such changes could materially affect NW Natural's investment account balances and the amounts reported as plan assets available for benefit payments.

The following tables present the fair value of NW Natural's Pension Plan assets, including outstanding receivables and liabilities, of NW Natural's retirement trust fund

In thousands	December 31, 2022				
Investments	Level 1	Level 2	Level 3	Non-Published NAV(1)	Total
US equity	$ —	$ —	$ —	$ 68,729	$ 68,729
International / Global equity	26,677	—	—	63,827	90,504
Liability hedging	—	—	—	94,823	94,823
Opportunistic	—	—	—	23,903	23,903
Cash and cash equivalents	—	—	—	2,345	2,345
Total investments	$ 26,677	$ —	$ —	$ 253,627	$ 280,304

	December 31, 2021				
Investments	Level 1	Level 2	Level 3	Non-Published NAV(1)	Total
US equity	$ —	$ —	$ —	$ 121,090	$ 121,090
International / Global equity	35,456	—	—	88,078	123,534
Liability hedging	—	—	—	118,464	118,464
Opportunistic	—	—	—	33,808	33,808
Cash and cash equivalents	—	—	—	2,321	2,321
Total investments	$ 35,456	$ —	$ —	$ 363,761	$ 399,217

	December 31,	
	2022	2021
Receivables:		
Accrued interest and dividend income	$ 7,703	$ —
Total receivables	7,703	—
Liabilities:		
Due to broker for securities purchased	(7,701)	—
Total investment in retirement trust	$ 280,306	$ 399,217

(1) The fair value for these investments is determined using Net Asset Value per share (NAV) as of December 31, as a practical expedient, and therefore they are not classified within the fair value hierarchy. These investments primarily consist of institutional investment products, for which the NAV is generally not publicly available.

11. INCOME TAX

The following table provides a reconciliation between income taxes calculated at the statutory federal tax rate and the provision for income taxes reflected in the NW Holdings and NW Natural statements of comprehensive income or loss for December 31:

	NW Holdings			NW Natural		
Dollars in thousands	2022	2021	2020	2022	2021	2020
Income taxes at federal statutory rate	$ 24,241	$ 22,275	$ 19,185	$ 25,746	$ 22,996	$ 19,248
Increase (decrease):						
State income tax, net of federal	10,139	9,962	6,389	10,504	10,150	6,385
Differences required to be flowed-through by regulatory commissions	(4,748)	(4,655)	(3,960)	(4,746)	(4,738)	(3,960)
Other, net	(502)	(176)	(532)	(468)	(75)	(578)
Total provision for income taxes	$ 29,130	$ 27,406	$ 21,082	$ 31,036	$ 28,333	$ 21,095
Effective tax rate	25.2%	25.8%	23.1%	25.3%	25.9%	23.0%

The NW Holdings and NW Natural effective income tax rates for 2022 compared to 2021 changed primarily due to lower income tax amortization in 2022 of the 2020 Oregon Corporate Activity Tax (CAT), which was subject to regulatory deferral when it became effective on January 1, 2020 and then amortized in income tax expense as recovery began in late 2020, 2021, and 2022.

The NW Holdings and NW Natural effective income tax rates for 2021 compared to 2020 changed primarily due to Oregon CAT, the majority of which is incurred because of Oregon regulated operations and for which rate recovery began on November 1, 2020.

The provision for current and deferred income taxes consists of the following at December 31:

	NW Holdings			NW Natural		
In thousands	2022	2021	2020	2022	2021	2020
Current						
Federal	$ 5,172	$ 6,508	$ 10,106	$ 7,442	$ 7,570	$ 11,092
State	6,551	6,281	5,971	7,307	7,540	5,357
Total current income taxes	11,723	12,789	16,077	14,749	15,110	16,449
Deferred						
Federal	11,124	8,289	2,888	10,298	7,915	1,921
State	6,283	6,328	2,117	5,989	5,308	2,725
Total deferred income taxes	17,407	14,617	5,005	16,287	13,223	4,646
Income tax provision	$ 29,130	$ 27,406	$ 21,082	$ 31,036	$ 28,333	$ 21,095

The following table summarizes the tax effect of significant items comprising NW Holdings and NW Natural's deferred income tax balances recorded at December 31:

	NW Holdings		NW Natural	
In thousands	2022	2021	2022	2021
Deferred tax liabilities:				
Plant and property	$ 326,326	$ 310,471	$ 320,121	$ 303,928
Leases receivable	36,873	38,123	36,873	38,123
Pension and postretirement obligations	22,973	23,097	22,973	23,097
Income tax regulatory asset	13,152	14,818	13,152	14,818
Lease right of use assets	21,272	21,362	21,084	21,350
Other	17,050	7,793	17,314	8,003
Total deferred income tax liabilities	$ 437,646	$ 415,664	$ 431,517	$ 409,319
Deferred income tax assets:				
Income tax regulatory liability	$ 48,270	$ 50,447	$ 48,018	$ 50,193
Lease liabilities	21,306	21,376	21,102	21,365
Other intangible assets	1,947	3,484	—	—
Net operating losses and credits carried forward	101	126	44	44
Total deferred income tax assets	$ 71,624	$ 75,433	$ 69,164	$ 71,602
Total net deferred income tax liabilities	$ 366,022	$ 340,231	$ 362,353	$ 337,717

At December 31, 2022 and 2021, regulatory income tax assets of $10.2 million and $12.4 million, respectively, were recorded by NW Natural, a portion of which is recorded in current assets. These regulatory income tax assets primarily represent future rate recovery of deferred tax liabilities, resulting from differences in NGD plant financial statement and tax bases and NGD plant removal costs, which were previously flowed through for rate making purposes and to take into account the additional future taxes, which will be generated by that recovery. These deferred tax liabilities, and the associated regulatory income tax assets, are currently being recovered through customer rates. At December 31, 2022 and 2021, regulatory income tax assets of $2.9 million and $2.4 million, respectively, were recorded by NW Natural, representing future recovery of deferred tax liabilities resulting from the equity portion of AFUDC. At December 31, 2021, a regulatory income tax asset of $0.4 million was recorded by NW Natural, representing future recovery of Oregon CAT that was deferred between January 1, 2020 and October 31,2020. In October 2020, the OPUC issued an order providing for recovery of deferred Oregon CAT as well as CAT incurred prospectively beginning November 1, 2020. This asset was fully recovered as of December 31, 2022.

At December 31, 2022 and 2021, deferred tax assets of $48.0 million and $50.2 million, respectively, were recorded by NW Natural representing the future income tax benefit associated with the excess deferred income tax regulatory liability recorded as a result of the lower federal corporate income tax rate provided for by the TCJA. At December 31, 2022 and 2021, regulatory liability balances representing the benefit of the change in deferred taxes as a result of the TCJA of $181.4 million and $189.6 million, respectively, were recorded by NW Natural.

NW Holdings and NW Natural assess the available positive and negative evidence to estimate if sufficient taxable income will be generated to utilize their respective existing deferred tax assets. Based upon this assessment, NW Holdings and NW Natural determined that it is more likely than not that all of their respective deferred tax assets recorded as of December 31, 2022 will be realized.

The Company estimates it has net operating loss (NOL) carryforwards of $0.1 million for federal taxes and $0.1 million for state taxes at December 31, 2022. The federal NOLs do not expire and we anticipate fully utilizing the state NOL carryforward balances before they begin to expire in 2040. California alternative minimum tax (AMT) credits of $56 thousand are also available. The AMT credits do not expire.

Uncertain tax positions are accounted for in accordance with accounting standards that require an assessment of the anticipated settlement outcome of material uncertain tax positions taken in a prior year, or planned to be taken in the current year. Until such positions are sustained, the uncertain tax benefits resulting from such positions would not be recognized. No reserves for uncertain tax positions were recorded as of December 31, 2022, 2021, or 2020.

The federal income tax returns for tax years 2018 and earlier are closed by statute. The IRS Compliance Assurance Process (CAP) examination of the 2019 and 2020 tax years have been completed. There were no material changes to these returns as filed. The 2021 and 2022 tax years are currently under IRS CAP examination. The 2023 CAP application has been filed. Under the CAP program, NW Holdings and NW Natural work with the IRS to identify and resolve material tax matters before the tax return is filed each year.

As of December 31, 2022, income tax years 2018 through 2021 remain open for examination by the State of California. Income tax years 2019 through 2021 are open for examination by the States of Oregon, Idaho, and Texas.

12. PROPERTY, PLANT, AND EQUIPMENT

The following table sets forth the major classifications of property, plant, and equipment and accumulated depreciation of continuing operations at December 31:

In thousands	2022	2021
NW Natural:		
NGD plant in service	$ 3,992,676	$ 3,721,939
NGD construction work in progress	78,897	135,398
Less: Accumulated depreciation	1,115,690	1,098,715
NGD plant, net	2,955,883	2,758,622
Other plant in service	70,368	69,332
Other construction work in progress	6,606	4,971
Less: Accumulated depreciation	21,541	20,646
Other plant, net	55,433	53,657
Total property, plant, and equipment	$ 3,011,316	$ 2,812,279
Other (NW Holdings):		
Other plant in service	$ 92,979	$ 57,184
Other construction work in progress	20,040	8,419
Less: Accumulated depreciation	9,935	6,512
Other plant, net	103,084	59,091
NW Holdings:		
Total property, plant, and equipment	$ 3,114,400	$ 2,871,370
NW Natural:		
Capital expenditures in accrued liabilities	$ 24,584	$ 37,537
NW Holdings:		
Capital expenditures in accrued liabilities	$ 25,318	$ 38,333

Accumulated depreciation does not include the accumulated provision for asset removal costs of $467.7 million and $446.0 million at December 31, 2022 and 2021, respectively. These accrued asset removal costs are reflected on the balance sheet as regulatory liabilities. See Note 2.

<u>NW Holdings</u>
Other plant balances include long-lived assets associated with water and wastewater operations and non-regulated activities not held by NW Natural or its subsidiaries.

<u>NW Natural</u>
Other plant balances include non-utility gas storage assets at the Mist facility and other long-lived assets not related to NGD.

The weighted average depreciation rate for NGD assets was 3.0% in 2022, 2021, and 2020. The weighted average depreciation rate for assets not related to NGD was 1.8% in 2022, 2021, and 2020.

13. INVESTMENTS

Investments include gas reserves, financial investments in life insurance policies, and equity method investments. The following table summarizes other investments at December 31:

	NW Holdings		NW Natural	
In thousands	2022	2021	2022	2021
Investments in life insurance policies	$ 49,358	$ 48,178	$ 49,358	$ 48,178
Investments in gas reserves, non-current	22,970	26,608	22,970	26,608
Investments in unconsolidated affiliates	23,376	14,492	7,782	—
Total other investments	$ 95,704	$ 89,278	$ 80,110	$ 74,786

Investment in Life Insurance Policies
NW Natural has invested in key person life insurance contracts to provide an indirect funding vehicle for certain long-term employee and director benefit plan liabilities. The amount in the above table is reported at cash surrender value, net of policy loans.

NW Natural Gas Reserves
NW Natural has invested $188 million through the gas reserves program in the Jonah Field located in Wyoming as of December 31, 2022. Gas reserves are stated at cost, net of regulatory amortization, with the associated deferred tax benefits of $5.2 million and $6.9 million, which are recorded as liabilities in the December 31, 2022 and 2021 consolidated balance sheets, respectively. NW Natural's investment is included in NW Holdings' and NW Natural's consolidated balance sheets under other current assets and other investments (non-current portion) with the maximum loss exposure limited to the investment balance. The amount of gas reserves included in other current assets was $3.4 million and $5.4 million as of December 31, 2022 and 2021, respectively. The investment in gas reserves provides long-term price protection and acted to hedge the cost of gas for approximately 3% and 4% of NGD gas supplies for the years ended December 31, 2022 and 2021, respectively.

Investments in Unconsolidated Affiliates
In December 2021, NW Natural Water purchased a 37.3% ownership stake in Avion Water Company, Inc. (Avion Water), an investor-owned water utility for $14.5 million. In July 2022, NW Natural Water increased its ownership stake in Avion Water to 40.3% for an additional $1.0 million. Avion Water operates in Bend, Oregon and the surrounding communities, serving approximately 15,000 customer connections and employing 35 people. The carrying value of the equity method investment is $9.4 million higher than the underlying equity in the net assets of the investee at December 31, 2022 due to equity method goodwill. Equity in earnings (loss) of Avion Water is included in other income (expense), net.

On August 6, 2020, NWN Energy completed the sale of 100% of its interest in Trail West Holdings, LLC (TWH) to an unrelated third party for a purchase price of $14.0 million, $7.0 million of which was paid upon closing the transaction, and $7.0 million of which was paid upon the one-year anniversary of the close date. The completion of the sale resulted in an after-tax gain of approximately $0.5 million for the year ended December 31, 2020. TWH was a variable interest entity reported under equity method accounting through its sale. The investment in TWH did not meet the criteria to be classified as held for sale or discontinued operations.

In 2020, NW Natural began a partnership with BioCarbN to invest in up to four separate RNG development projects that are designed to access biogas derived from water treatment at Tyson Foods' processing plants, subject to approval by all parties. During the construction phase of the projects, NW Natural determined it is the primary beneficiary and fully consolidates each entity.

In 2022, commissioning of the first project, Lexington Renewable Energy LLC (Lexington), was completed and NW Natural determined it was no longer the primary beneficiary and deconsolidated the variable interest entity and recorded the investment in Lexington as an equity method investment. NW Natural accounts for its interest in Lexington using the equity method of accounting because NW Natural does not control but has the ability to exercise significant influence over Lexington's operations after commissioning. There was no gain or loss recognized upon deconsolidation. NW Natural determined the fair value of the investment approximated the carrying value which was primarily comprised of cash and property, plant and equipment. As of December 31, 2022, NW Natural had an investment balance in Lexington of $7.8 million. Equity in earnings (loss) of Lexington is included in cost of gas.

14. BUSINESS COMBINATIONS

2022 Business Combinations

Far West Water & Sewer, Inc.

On October 5, 2022, NWN Water completed the acquisition of the water and wastewater utilities of Far West Water & Sewer, Inc. (Far West), which has a combined approximately 25,000 connections in Yuma, Arizona. The acquisition-date fair value of the total consideration transferred, after closing adjustments, was approximately $97.0 million, of which $88.4 million was cash consideration transferred at closing, $8.1 million was contingent consideration, and $0.5 million was deferred consideration.

The contingent consideration is an earnout payment in an amount equal to the product of (i) the amount, if any, by which the average annual System Operating Revenue for the 2026, 2027, and 2028 years exceeds $13.0 million (ii) multiplied by 4 but shall not exceed $12.0 million. As of the acquisition date, the contingent consideration had a fair value of $8.1 million and was included in other non-current liabilities. The fair value as of the acquisition date was determined using a scenario-based technique using management's best estimate of forecast revenue for the years 2026, 2027, and 2028 discounted to present value. The inputs to determine the fair value of the contingent consideration include estimated future revenue and a risk-adjusted discount rate. The fair value measurement is based on significant inputs that are not observable in the market and thus represents a fair value measurement categorized within Level 3 of the fair value hierarchy per ASC Topic 820.

The Far West acquisition met the criteria of a business combination, and as such a preliminary allocation of the consideration to the acquired net assets based on their estimated fair value as of the acquisition date was performed. In accordance with U.S. GAAP, the fair value determination involves management judgment in determining the significant estimates and assumptions used and was made using existing regulatory conditions for net assets associated with Far West. This allocation is considered preliminary as of December 31, 2022, as facts and circumstances that existed as of the acquisition date may be discovered as we continue to integrate Far West. As a result, subsequent adjustments to the preliminary valuation of tangible assets, contract assets and liabilities, tax positions, and goodwill may be required. Subsequent adjustments are not expected to be significant, and any such adjustments are expected to be completed within the one-year measurement period. The acquisition costs were expensed as incurred.

Preliminary goodwill of $70.8 million was recognized from this acquisition. The goodwill recognized is attributable to Far West's regulated water utility service territory, experienced workforce, and the strategic benefits for both the water utility and wastewater services expected from growth in its service territory. No intangible assets aside from goodwill were recognized. The amount of goodwill that is expected to be deductible for income tax purposes is approximately $61.8 million

The preliminary purchase price for the acquisition has been allocated to the net assets acquired as of the acquisition date and is as follows:

In thousands	December 31, 2022
Current assets	$ 1,281
Property, plant and equipment	25,744
Goodwill	70,842
Non-current assets	684
Current liabilities	(1,136)
Non-current liabilities	(9,011)
Total net assets acquired	$ 88,404

The amount of Far West revenues included in NW Holdings' consolidated statements of comprehensive income is $2.9 million for the year ended December 31, 2022. Earnings from Far West activities for the year ended December 31, 2022 were not material to the results of NW Holdings. Far West is referred to as Foothills Utilities following the closure of the acquisition.

Other 2022 Business Combinations

During the year ended December 31, 2022, NWN Water and its subsidiaries acquired the assets of six additional businesses qualifying as business combinations. The aggregate fair value of the preliminary consideration transferred for these acquisitions was $8.7 million, most of which was preliminarily allocated to property, plant and equipment and goodwill. These transactions align with NW Holdings' water and wastewater sector strategy as it continues to expand its water and wastewater service territories and included:

- Belle Oaks Water and Sewer Co., Inc in Texas
- Northwest Water Services, LLC in Washington
- Aquarius Utilities, LLC in Washington
- Valiant Idaho, LLC (The Idaho Club - Sewer) in Idaho
- Caney Creek in Texas
- Water Necessities, Inc. and Rural Water Co. in Texas

2021 Business Combinations
During the year ended December 31, 2021, NWN Water and its subsidiaries completed four acquisitions qualifying as business combinations. The aggregate fair value of the consideration transferred for these acquisitions were not material and are not significant to NW Holdings' results of operations.

2020 Business Combinations
During the year ended December 31, 2020, NWN Water and its subsidiaries completed two significant acquisitions qualifying as business combinations. The aggregate fair value of the total cash consideration transferred for these acquisitions was $38.1 million, most of which was allocated to property, plant and equipment and goodwill. These transactions align with NW Holdings' water sector strategy as it continues to expand its water services territories in the Pacific Northwest and beyond and included:

- Suncadia Water Company, LLC and Suncadia Environmental Company, LLC which were acquired by NWN Water of Washington on January 31, 2020, and
- T&W Water Service Company which was acquired by NWN Water of Texas on March 2, 2020. T&W Water Service Company is referred to as Blue Topaz Utilities following the closure of the acquisition.

Other 2020 Business Combinations
During the year ended December 31, 2020, NWN Water completed three additional acquisitions, comprised of four water systems and one wastewater system, which qualified as business combinations. The aggregate fair value of the consideration transferred for these acquisitions was approximately $1.5 million. These business combinations were not significant to NW Holdings' results of operations.

Goodwill
NW Holdings allocates goodwill to reporting units based on the expected benefit from the business combination. We perform an annual impairment assessment of goodwill at the reporting unit level, or more frequently if events and circumstances indicate that goodwill might be impaired. An impairment loss is recognized if the carrying value of a reporting unit's goodwill exceeds its fair value.

As a result of all acquisitions completed, total goodwill was $149.3 million as of December 31, 2022 and $70.6 million as of December 31, 2021. The increase in the goodwill balance was primarily due to additions associated with our acquisitions in the water and wastewater sector. All of our goodwill is related to water and wastewater acquisitions and is included in the other category for segment reporting purposes. The annual impairment assessment of goodwill occurs in the fourth quarter of each year. There have been no impairments recognized to date.

15. DERIVATIVE INSTRUMENTS

NW Natural
NW Natural enters into financial derivative contracts to hedge a portion of the NGD segment's natural gas sales requirements. These contracts include swaps, options, and combinations of option contracts. These derivative financial instruments are primarily used to manage commodity price variability. A small portion of NW Natural's derivative hedging strategy involves foreign currency forward contracts.

NW Natural enters into these financial derivatives, up to prescribed limits, primarily to hedge price variability related to term physical gas supply contracts as well as to hedge spot purchases of natural gas. The foreign currency forward contracts are used to hedge the fluctuation in foreign currency exchange rates for pipeline demand charges paid in Canadian dollars.

In the normal course of business, NW Natural also enters into indexed-price physical forward natural gas commodity purchase contracts and options to meet the requirements of NGD customers. These contracts qualify for regulatory deferral accounting treatment.
NW Natural also enters into exchange contracts related to the third-party asset management of its gas portfolio, some of which are derivatives that do not qualify for hedge accounting or only partial regulatory deferral, but are subject to NW Natural's regulatory sharing agreement. These derivatives are recognized in operating revenues, net of amounts shared with NGD customers.

Notional Amounts
The following table presents the absolute notional amounts related to open positions on NW Natural derivative instruments:

	At December 31,	
In thousands	2022	2021
Natural gas (in therms):		
Financial	852,435	618,815
Physical	463,254	431,628
Foreign exchange	$ 7,617	$ 6,268

Purchased Gas Adjustment (PGA)

Under the PGA mechanism in Oregon, derivatives entered into by NW Natural for the procurement or hedging of natural gas for future gas years generally receive regulatory deferral accounting treatment. In general, commodity hedging for the current gas year is completed prior to the start of the gas year, and hedge prices are reflected in the weighted-average cost of gas in the PGA filing. Rates and hedging approaches may vary between states due to different rate structures and mechanisms. In addition, as required with the Washington PGA filing, NW Natural incorporated and began implementing risk-responsive hedging strategies for its Washington gas supplies. Hedge contracts entered into after the start of the PGA period are subject to the PGA incentive sharing mechanism in Oregon. NW Natural entered the 2022-23 and 2021-22 gas years with forecasted sales volumes hedged at 67% and 60% in financial swap and option contracts, and 17% and 19% in physical gas supplies, respectively. Hedge contracts entered into prior to the PGA filing, in September 2022, were included in the PGA for the 2022-23 gas year. Hedge contracts entered into after the PGA filing, and related to subsequent gas years, may be included in future PGA filings and qualify for regulatory deferral.

Unrealized and Realized Gain/Loss

The following table reflects the income statement presentation for the unrealized gains and losses from NW Natural's derivative instruments:

	December 31, 2022		December 31, 2021	
In thousands	Natural gas commodity	Foreign exchange	Natural gas commodity	Foreign exchange
Benefit (expense) to cost of gas	$ 119,935	$ (165)	$ 36,539	$ (26)
Operating revenues (expense)	—	—	(26)	—
Amounts deferred to regulatory accounts on balance sheet	(119,935)	165	(36,517)	26
Total gain (loss) in pre-tax earnings	$ —	$ —	$ (4)	$ —

Unrealized Gain/Loss

Outstanding derivative instruments related to regulated NGD operations are deferred in accordance with regulatory accounting standards. The cost of foreign currency forward and natural gas derivative contracts are recognized immediately in the cost of gas; however, costs above or below the amount embedded in the current year PGA are subject to a regulatory deferral tariff and therefore, are recorded as a regulatory asset or liability.

Realized Gain/Loss

NW Natural realized net gains of $107.8 million and $50.9 million for the years ended December 31, 2022 and 2021, respectively, from the settlement of natural gas financial derivative contracts. Realized gains and losses offset the higher or lower cost of gas purchased, resulting in no incremental amounts to collect or refund to customers.

Credit Risk Management of Financial Derivatives Instruments

No collateral was posted with or by NW Natural counterparties as of December 31, 2022 or 2021. NW Natural attempts to minimize the potential exposure to collateral calls by diversifying counterparties and using credit limits to manage liquidity risk. Counterparties generally allow a certain credit limit threshold before requiring NW Natural to post collateral against unrealized loss positions. Given NW Natural's credit ratings, counterparty credit limits and portfolio diversification, it was not subject to collateral calls in 2022 or 2021. The collateral call exposure is set forth under credit support agreements, which generally contain credit limits. NW Natural could also be subject to collateral call exposure where it has agreed to provide adequate assurance, which is not specific as to the amount of credit limit allowed, but could potentially require additional collateral posting by NW Natural in the event of a material adverse change.

NW Natural's financial derivative instruments are subject to master netting arrangements; however, they are presented on a gross basis in the consolidated balance sheets. NW Natural and its counterparties have the ability to set-off obligations to each other under specified circumstances. Such circumstances may include a defaulting party, a credit change due to a merger affecting either party, or any other termination event.

If netted by counterparty, NW Natural's physical and financial derivative position would result in an asset of $153.3 million and a liability of $3.6 million as of December 31, 2022, and an asset of $51.8 million and a liability of $3.8 million as of December 31, 2021.

NW Natural is exposed to derivative credit and liquidity risk primarily through securing fixed price natural gas commodity swaps with financial counterparties. NW Natural utilizes master netting arrangements through International Swaps and Derivatives Association contracts to minimize this risk along with collateral support agreements with counterparties based on their credit ratings. Additionally, NW Natural uses counterparty, industry, sector and country diversification to minimize credit risk. In certain cases, NW Natural may require counterparties to post collateral, guarantees, or letters of credit to maintain its minimum credit requirement standards.

NW Natural's financial derivatives policy requires counterparties to have an investment-grade credit rating at the time the derivative instrument is entered into, and specifies limits on the contract amount and duration based on each counterparty's credit rating. NW Natural does not speculate in derivatives. Derivatives are used to reduce NW Natural's net market risk and hedge exposure above risk tolerance limits. It is required that increases in market risk created by the use of derivatives is offset by the exposures they modify.

We actively monitor NW Natural's derivative credit exposure and place counterparties on hold for trading purposes or require other forms of credit assurance, such as letters of credit, cash collateral, or guarantees as circumstances warrant. The ongoing assessment of counterparty credit risk includes consideration of credit ratings, credit default swap spreads, bond market credit spreads, financial condition, government actions, and market news. A Monte Carlo simulation model is used to estimate the change in credit and liquidity risk from the volatility of natural gas prices. The results of the model are used to establish trading limits. NW Natural's outstanding financial derivatives at December 31, 2022 mature by November 1, 2025.

We could become materially exposed to credit risk with one or more of our counterparties if natural gas prices experience a significant increase. If a counterparty were to become insolvent or fail to perform on its obligations, we could suffer a material loss; however, we would expect such a loss to be eligible for regulatory deferral and rate recovery, subject to a prudence review. All of our existing counterparties currently have investment-grade credit ratings.

Fair Value

In accordance with fair value accounting, NW Natural includes non-performance risk in calculating fair value adjustments. This includes a credit risk adjustment based on the credit spreads of NW Natural counterparties when in an unrealized gain position, or on NW Natural's own credit spread when it is in an unrealized loss position. The inputs in our valuation models include natural gas futures, volatility, credit default swap spreads, and interest rates. Additionally, the assessment of non-performance risk is generally derived from the credit default swap market and from bond market credit spreads. The impact of the credit risk adjustments for all financial derivatives outstanding was immaterial to the fair value calculation at December 31, 2022. As of December 31, 2022 and 2021, the net fair value was an asset of $149.7 million and $48.0 million, respectively, using significant other observable, or Level 2, inputs. No Level 3 inputs were used in our derivative valuations during the years ended December 31, 2022 and 2021.

NW Holdings

NW Holdings and NWN Water entered into interest rate swap agreements with major financial institutions that effectively convert variable-rate debt to a fixed rate. Interest payments made between the effective date and expiration date are hedged by the swap agreements. The notional amount, effective date, expiration date and rate of the swap agreements are shown in the table below:

In millions	Notional Amount	Effective Date	Expiration Date	Fixed Rate
NW Holdings	$ 100.0	1/17/2023	3/15/2024	4.7 %
NWN Water	$ 55.0	1/19/2023	6/10/2026	3.8 %

Unrealized gains and losses related to these interest rate swap agreements are recorded in AOCI on the consolidated balance sheet and totaled $129 thousand, net of tax, as of December 31, 2022. There were no amounts reclassified from AOCI to net income during the year ended December 31, 2022.

16. COMMITMENTS AND CONTINGENCIES

Gas Purchase and Pipeline Capacity Purchase and Release Commitments

NW Natural has signed agreements providing for the reservation of firm pipeline capacity under which it is required to make fixed monthly payments for contracted capacity. The pricing component of the monthly payment is established, subject to change, by U.S. or Canadian regulatory bodies, or is established directly with private counterparties, as applicable. In addition, NW Natural has entered into long-term agreements to release firm pipeline capacity. NW Natural also enters into short-term and long-term gas purchase agreements.

In November 2021, NW Natural and a subsidiary of Archaea Energy entered into a long-term RNG purchase and sale agreement. Under the agreement, NW Natural committed to purchase the environmental attributes generated by Archaea related to up to ten million therms of RNG annually from its portfolio of RNG production facilities for a fixed fee for a period of 21 years. The agreement commenced in 2022, with the full annual quantity beginning in 2025.

The aggregate amounts of these agreements at NW Natural were as follows at December 31, 2022:

In thousands	Gas Purchase Agreements[1]	Pipeline Capacity Purchase Agreements	Pipeline Capacity Release Agreements
2023	$ 400,370	$ 81,691	$ 8,154
2024	6,376	77,327	7,474
2025	6,426	78,493	3,397
2026	12,003	66,782	—
2027	11,330	66,906	—
Thereafter	189,050	432,464	—
Total	625,555	803,663	19,025
Less: Amount representing interest	86,250	200,243	989
Total at present value	$ 539,305	$ 603,420	$ 18,036

[1] Gas purchase agreements include environmental attributes of RNG.

Total fixed charges under capacity purchase agreements were $90.2 million for 2022, $82.9 million for 2021, and $81.8 million for 2020, of which $8.3 million, $7.7 million, and $4.8 million, respectively, related to capacity releases. In addition, per-unit charges are required to be paid based on the actual quantities shipped under the agreements. In certain take-or-pay purchase commitments, annual deficiencies may be offset by prepayments subject to recovery over a longer term if future purchases exceed the minimum annual requirements.

Leases
Refer to Note 7 for a discussion of lease commitments and contingencies.

Environmental Matters
Refer to Note 17 for a discussion of environmental commitments and contingencies.

17. ENVIRONMENTAL MATTERS

NW Natural owns, or previously owned, properties that may require environmental remediation or action. The range of loss for environmental liabilities is estimated based on current remediation technology, enacted laws and regulations, industry experience gained at similar sites, and an assessment of the probable level of involvement and financial condition of other potentially responsible parties (PRPs). When amounts are prudently expended related to site remediation of those sites described herein, NW Natural has recovery mechanisms in place to collect 96.7% of remediation costs allocable to Oregon customers and 3.3% of costs allocable to Washington customers.

These sites are subject to the remediation process prescribed by the Environmental Protection Agency (EPA) and the Oregon Department of Environmental Quality (ODEQ). The process begins with a remedial investigation (RI) to determine the nature and extent of contamination and then a risk assessment (RA) to establish whether the contamination at the site poses unacceptable risks to humans and the environment. Next, a feasibility study (FS) or an engineering evaluation/cost analysis (EE/CA) evaluates various remedial alternatives. It is at this point in the process when NW Natural is able to estimate a range of remediation costs and record a reasonable potential remediation liability, or make an adjustment to the existing liability. From this study, the regulatory agency selects a remedy and issues a Record of Decision (ROD). After a ROD is issued, NW Natural would seek to negotiate a consent decree or consent judgment for designing and implementing the remedy. NW Natural would have the ability to further refine estimates of remediation liabilities at that time.

Remediation may include treatment of contaminated media such as sediment, soil and groundwater, removal and disposal of media, institutional controls such as legal restrictions on future property use, or natural recovery. Following construction of the remedy, the EPA and ODEQ also have requirements for ongoing maintenance, monitoring and other post-remediation care that may continue for many years. Where appropriate and reasonably known, NW Natural will provide for these costs in the remediation liabilities described below.

Due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, NW Natural may not be able to reasonably estimate the high end of the range of possible loss. In those cases, the nature of the possible loss has been disclosed, as has the fact that the high end of the range cannot be reasonably estimated where a range of potential loss is available. Unless there is an estimate within the range of possible losses that is more likely than other cost estimates within that range, NW Natural records the liability at the low end of this range. It is likely changes in these estimates and ranges will occur throughout the remediation process for each of these sites due to the continued evaluation and clarification concerning responsibility, the complexity of environmental laws and regulations and the determination by regulators of remediation alternatives. In addition to remediation costs, NW Natural could also be subject to

Natural Resource Damages (NRD) claims. NW Natural will assess the likelihood and probability of each claim and recognize a liability if deemed appropriate. Refer to "*Other Portland Harbor*" below.

Environmental Sites

The following table summarizes information regarding liabilities related to environmental sites, which are recorded in other current liabilities and other noncurrent liabilities in NW Natural's balance sheet at December 31:

	Current Liabilities		Non-Current Liabilities	
In thousands	2022	2021	2022	2021
Portland Harbor site:				
Gasco/Siltronic Sediments	$ 9,744	$ 7,582	$ 42,120	$ 42,076
Other Portland Harbor	2,634	2,592	11,270	9,570
Gasco/Siltronic Upland site	16,067	15,711	35,457	36,215
Front Street site	457	1,100	879	811
Oregon Steel Mills	—	—	179	179
Total	$ 28,902	$ 26,985	$ 89,905	$ 88,851

Portland Harbor Site

The Portland Harbor is an EPA listed Superfund site that is approximately 10 miles long on the Willamette River and is adjacent to NW Natural's Gasco uplands site. NW Natural is one of over one hundred PRPs, each jointly and severally liable, at the Superfund site. In January 2017, the EPA issued its Record of Decision, which selects the remedy for the clean-up of the Portland Harbor site (Portland Harbor ROD). The Portland Harbor ROD estimates the present value total cost at approximately $1.05 billion with an accuracy between -30% and +50% of actual costs.

NW Natural's potential liability is a portion of the costs of the remedy for the entire Portland Harbor Superfund site. The cost of that remedy is expected to be allocated among more than one hundred PRPs. NW Natural is participating in a non-binding allocation process with other PRPs in an effort to resolve its potential liability. The Portland Harbor ROD does not provide any additional clarification around allocation of costs among PRPs; accordingly, NW Natural has not modified any of the recorded liabilities at this time as a result of the issuance of the Portland Harbor ROD.

NW Natural manages its liability related to the Superfund site as two distinct remediation projects, the Gasco Sediments Site and Other Portland Harbor projects.

GASCO SEDIMENTS. In 2009, NW Natural and Siltronic Corporation entered into a separate Administrative Order on Consent with the EPA to evaluate and design specific remedies for sediments adjacent to the Gasco uplands and Siltronic uplands sites. NW Natural submitted a draft EE/CA to the EPA in May 2012 to provide the estimated cost of potential remedial alternatives for this site. In March 2020, NW Natural and the EPA amended the Administrative Order on Consent to include additional remedial design activities downstream of the Gasco sediments site and in the navigation channel. Siltronic Corporation is not a party to the amended order. In the second quarter of 2021, NW Natural began preliminary design discussions with the EPA for the Gasco sediments site. These preliminary design discussions did not include a cost estimate for cleanup. No design alternatives are more likely than the EE/CA alternatives at this time, and NW Natural expects further design discussion and iteration with the EPA.

The estimated costs for the various sediment remedy alternatives in the draft EE/CA for the additional studies and design work needed before the cleanup can occur, and for regulatory oversight throughout the cleanup range from $51.9 million to $350 million. NW Natural has recorded a liability of $51.9 million for the Gasco sediment clean-up, which reflects the low end of the range. At this time, we believe sediments at the Gasco sediments site represent the largest portion of NW Natural's liability related to the Portland Harbor site discussed above.

OTHER PORTLAND HARBOR. While we believe liabilities associated with the Gasco sediments site represent NW Natural's largest exposure, there are other potential exposures associated with the Portland Harbor ROD, including NRD costs and harborwide remedial design and cleanup costs (including downstream petroleum contamination), for which allocations among the PRPs have not yet been determined.

NW Natural and other parties have signed a cooperative agreement with the Portland Harbor Natural Resource Trustee council to participate in a phased NRD assessment to estimate liabilities to support an early restoration-based settlement of NRD claims. One member of this Trustee council, the Yakama Nation, withdrew from the council in 2009, and in 2017, filed suit against NW Natural and 29 other parties seeking remedial costs and NRD assessment costs associated with the Portland Harbor site, set forth in the complaint. The complaint seeks recovery of alleged costs totaling $0.3 million in connection with the selection of a remedial action for the Portland Harbor site as well as declaratory judgment for unspecified future remedial action costs and for costs to assess the injury, loss or destruction of natural resources resulting from the release of hazardous substances at and from the Portland Harbor site. The Yakama Nation has filed two amended complaints addressing certain pleading defects and dismissing the State of Oregon. On the motion of NW Natural and certain other defendants the federal court has stayed the case pending the outcome of the non-binding allocation proceeding discussed above. NW Natural has recorded a liability for NRD claims which is at the low end of the range of the potential liability; the high end of the range cannot be reasonably estimated at this time. The NRD liability is not included in the aforementioned range of costs provided in the Portland Harbor ROD.

Gasco Uplands Site
A predecessor of NW Natural, Portland Gas and Coke Company, owned a former gas manufacturing plant that was closed in 1958 (Gasco site) and is adjacent to the Portland Harbor site described above. The Gasco site has been under investigation by NW Natural for environmental contamination under the ODEQ Voluntary Cleanup Program (VCP). It is not included in the range of remedial costs for the Portland Harbor site noted above. The Gasco site is managed in two parts, the uplands portion and the groundwater source control action.

NW Natural submitted a revised Remedial Investigation Report for the uplands to ODEQ in May 2007. In March 2015, ODEQ approved the Risk Assessment (RA) for this site, enabling commencement of work on the FS in 2016. NW Natural has recognized a liability for the remediation of the uplands portion of the site which is at the low end of the range of potential liability; the high end of the range cannot be reasonably estimated at this time.

In October 2016, ODEQ and NW Natural agreed to amend their VCP agreement for the Gasco uplands to incorporate a portion of the Siltronic property formerly owned by Portland Gas & Coke between 1939 and 1960 into the Gasco RA and FS. Previously, NW Natural was conducting an investigation of manufactured gas plant constituents on the entire Siltronic uplands for ODEQ. Siltronic will be working with ODEQ directly on environmental impacts to the remainder of its property.

In September 2013, NW Natural completed construction of a groundwater source control system, including a water treatment station, at the Gasco site. NW Natural has estimated the cost associated with the ongoing operation of the system and has recognized a liability which is at the low end of the range of potential cost. NW Natural cannot estimate the high end of the range at this time due to the uncertainty associated with the duration of running the water treatment station, which is highly dependent on the remedy determined for both the upland portion as well as the final remedy for the Gasco sediments site.

Other Sites
In addition to those sites above, NW Natural has environmental exposures at three other sites: Central Service Center, Front Street and Oregon Steel Mills. NW Natural may have exposure at other sites that have not been identified at this time. Due to the uncertainty of the design of remediation, regulation, timing of the remediation and in the case of the Oregon Steel Mills site, pending litigation, liabilities for each of these sites have been recognized at their respective low end of the range of potential liability; the high end of the range could not be reasonably estimated at this time.

FRONT STREET SITE. The Front Street site was the former location of a gas manufacturing plant NW Natural operated (the former Portland Gas Manufacturing site, or PGM). At ODEQ's request, NW Natural conducted a sediment and source control investigation and provided findings to ODEQ. In December 2015, an FS on the former Portland Gas Manufacturing site was completed.

In July 2017, ODEQ issued the PGM ROD. The ROD specifies the selected remedy, which requires a combination of dredging, capping, treatment, and natural recovery. In addition, the selected remedy also requires institutional controls and long-term inspection and maintenance. Construction of the remedy began in July 2020 and was completed in October 2020. The first year of post-construction monitoring was completed in 2021 and demonstrated that the cap was intact and performing as designed. NW Natural has recognized an additional liability of $1.3 million for costs associated with the discovery during construction of World War II-era munitions, design costs, regulatory and permitting issues, and post-construction work.

OREGON STEEL MILLS SITE. Refer to "Legal Proceedings," below.

Environmental Cost Deferral and Recovery
NW Natural has authorizations in Oregon and Washington to defer costs related to remediation of properties that are owned or were previously owned by NW Natural. In Oregon, a Site Remediation and Recovery Mechanism (SRRM) is currently in place to recover prudently incurred costs allocable to Oregon customers, subject to an earnings test. On October 21, 2019 the WUTC authorized an Environmental Cost Recovery Mechanism (ECRM) for recovery of prudently incurred costs allocable to Washington customers beginning November 1, 2019.

The following table presents information regarding the total regulatory asset deferred as of December 31:

In thousands		2022		2021
Deferred costs and interest[1]	$	47,666	$	45,122
Accrued site liabilities[2]		118,763		115,773
Insurance proceeds and interest		(54,784)		(59,564)
Total regulatory asset deferral[1]	$	111,645	$	101,331
Current regulatory assets[3]	$	7,392	$	6,694
Long-term regulatory assets[3]	$	104,253	$	94,636

(1) Includes pre-review and post-review deferred costs, amounts currently in amortization, and interest, net of amounts collected from customers.
(2) Excludes 3.3% of the Front Street site liability as the OPUC only allows recovery of 96.7% of costs for those sites allocable to Oregon, including those that historically served only Oregon customers. Amounts excluded from regulatory assets were $43 thousand in 2022 and $62 thousand in 2021.
(3) Environmental costs relate to specific sites approved for regulatory deferral by the OPUC and WUTC. In Oregon, NW Natural earns a carrying charge on cash amounts paid, whereas amounts accrued but not yet paid do not earn a carrying charge until expended. It also accrues a carrying charge on insurance proceeds for amounts owed to customers. In Washington, neither the cash paid nor insurance proceeds received accrue a carrying charge. Current environmental costs represent remediation costs management expects to collect from customers in the next 12 months. Amounts included in this estimate are still subject to a prudence and earnings test review by the OPUC and do not include the $5.0 million tariff rider. The amounts allocable to Oregon are recoverable through NGD rates, subject to an earnings test. See "*Oregon SRRM*" below.

Oregon SRRM

Collections From Oregon Customers

Under the SRRM collection process, there are three types of deferred environmental remediation expense:

- Pre-review - This class of costs represents remediation spend that has not yet been deemed prudent by the OPUC. Carrying costs on these remediation expenses are recorded at NW Natural's authorized cost of capital. NW Natural anticipates the prudence review for annual costs and approval of the earnings test prescribed by the OPUC to occur by the third quarter of the following year.
- Post-review - This class of costs represents remediation spend that has been deemed prudent and allowed after applying the earnings test, but is not yet included in amortization. NW Natural earns a carrying cost on these amounts at a rate equal to the five-year treasury rate plus 100 basis points.
- Amortization - This class of costs represents amounts included in current customer rates for collection and is generally calculated as one-fifth of the post-review deferred balance. NW Natural earns a carrying cost equal to the amortization rate determined annually by the OPUC, which approximates a short-term borrowing rate.

In addition to the collection amount noted above, an order issued by the OPUC provides for the annual collection of $5.0 million from Oregon customers through a tariff rider. As NW Natural collects amounts from customers, it recognizes these collections as revenue and separately amortizes an equal and offsetting amount of its deferred regulatory asset balance through the environmental remediation operating expense line shown separately in the operating expense section of the income statement.

NW Natural received total environmental insurance proceeds of approximately $150 million as a result of settlements from litigation that was dismissed in July 2014. Under a 2015 OPUC order which established the SRRM, one-third of the Oregon allocated proceeds were applied to costs deferred through 2012 with the remaining two-thirds applied to costs at a rate of $5.0 million per year plus interest over the following 20 years. NW Natural accrues interest on the Oregon allocated insurance proceeds in the customer’s favor at a rate equal to the five-year treasury rate plus 100 basis points. As of December 31, 2022, NW Natural has applied $95.0 million of insurance proceeds to prudently incurred remediation costs allocated to Oregon.

Environmental Earnings Test

To the extent NW Natural earns at or below its authorized Return on Equity (ROE) as defined by the SRRM, remediation expenses and interest in excess of the $5.0 million tariff rider and $5.0 million insurance proceeds are recoverable through the SRRM. To the extent NW Natural earns more than its authorized ROE in a year, it is required to cover environmental expenses and interest on expenses greater than the $10.0 million with those earnings that exceed its authorized ROE.

Washington ECRM

Washington Deferral

On October 21, 2019, the WUTC issued an order (WUTC Order) establishing the ECRM which allows for recovery of past deferred and future prudently incurred environmental remediation costs allocable to Washington customers through application of insurance proceeds and collections from customers. Environmental remediation expenses relating to sites that previously served both Oregon and Washington customers are allocated between states with Washington customers receiving 3.3% percent of the costs and insurance proceeds.

In accordance with the WUTC Order, insurance proceeds were fully applied to costs incurred between December 2018 and June 2019 that were deemed prudent. Remaining insurance proceeds will be amortized over a 10.5 year period ending December 31, 2029. As of December 31, 2022, approximately $3.9 million of proceeds have been applied to prudently incurred costs.

On an annual basis, NW Natural files for a prudence determination and a request to amortize costs to the extent that remediation expenses exceed the insurance amortization. After insurance proceeds are fully amortized, if in a particular year the request to collect deferred amounts exceeds one percent of Washington normalized revenues, then the excess will be collected over three years with interest.

Legal Proceedings

NW Holdings is not currently party to any direct claims or litigation, though in the future it may be subject to claims and litigation arising in the ordinary course of business.

NW Natural is subject to claims and litigation arising in the ordinary course of business, including the matters discussed above. Although the final outcome of any of these legal proceedings cannot be predicted with certainty, including the matter relating to the Oregon Steel Mills site referenced below, NW Natural and NW Holdings do not expect that the ultimate disposition of any of these matters will have a material effect on their financial condition, results of operations, or cash flows. See also Part II, Item 1, “Legal Proceedings".

Oregon Steel Mills Site

In 2004, NW Natural was served with a third-party complaint by the Port of Portland (the Port) in a Multnomah County Circuit Court case, Oregon Steel Mills, Inc. v. The Port of Portland. The Port alleges that in the 1940s and 1950s petroleum wastes generated by NW Natural's predecessor, Portland Gas & Coke Company, and 10 other third-party defendants, were disposed of in a waste oil disposal facility operated by the United States or Shaver Transportation Company on property then owned by the Port and now owned by Evraz Oregon Steel Mills. The complaint seeks contribution for unspecified past remedial action costs incurred by the Port regarding the former waste oil disposal facility as well as a declaratory judgment allocating liability for future remedial action costs. No date has been set for trial. In August 2017, the case was stayed pending the outcome of the Portland Harbor allocation process or other mediation. Although the final outcome of this proceeding cannot be predicted with certainty, NW Natural and NW Holdings do not expect the ultimate disposition of this matter will have a material effect on NW Natural's or NW Holdings' financial condition, results of operations, or cash flows.

For additional information regarding other commitments and contingencies, see Note 16.

18. DISCONTINUED OPERATIONS

NW Holdings

On June 20, 2018, NWN Gas Storage, then a wholly-owned subsidiary of NW Natural, entered into a Purchase and Sale Agreement (the Agreement) that provided for the sale by NWN Gas Storage of all of the membership interests in Gill Ranch. Gill Ranch owns a 75% interest in the natural gas storage facility located near Fresno, California known as the Gill Ranch Gas Storage Facility.

On December 4, 2020, NWN Gas Storage closed the sale of all of the membership interests in Gill Ranch and received payment of the initial cash purchase price of $13.5 million less the $1.0 million deposit previously paid. Furthermore, additional payments to NWN Gas Storage may be made subject to a maximum amount of $15.0 million in the aggregate (subject to a working capital adjustment) based on the economic performance of Gill Ranch for each full gas storage year (April 1 of one year through March 31 of the following year) occurring after the closing and the remaining portion of the 2020-2021 gas storage year and will continue until such time as the maximum amount has been paid. The fair value of this arrangement at the closing date was zero based on a discounted cash flow forecast. Subsequent changes in the fair value will be recorded in earnings. The completion of the sale resulted in an after-tax gain of $5.9 million for the year ended December 31, 2020.

The following table presents the operating results of Gill Ranch and is presented net of tax on NW Holdings' consolidated statements of comprehensive income:

In thousands	NW Holdings Discontinued Operations 2020
Revenues	$ 10,193
Expenses	
Operations and maintenance	7,931
General taxes	198
Depreciation	391
Other expenses and interest	848
Total expenses	9,368
Income from discontinued operations	825
Gain on sale of discontinued operations	8,027
Income from discontinued operations before income tax	8,852
Income tax expense[1]	2,344
Income from discontinued operations, net of tax	$ 6,508

[1] Includes income tax expense of $2.1 million related to the sale of Gill Ranch for the year ended December 31, 2020.

As a result of the disposition of the membership interests of Gill Ranch, there were no assets or liabilities classified as held for sale at December 31, 2020.

19. SUBSEQUENT EVENT

On January 6, 2023, NW Natural issued and sold $100.0 million aggregate principal amount of its FMBs, 5.43% Series due January 6, 2053 (the Bonds), to certain institutional investors pursuant to a Bond Purchase Agreement dated December 13, 2022. The Bonds bear interest at the rate of 5.43% per annum, payable semi-annually on January 6 and July 6 of each year, commencing July 6, 2023, and will mature on January 6, 2053. The Bonds will be subject to redemption prior to maturity at the option of NW Natural, in whole or in part, (i) at any time prior to July 6, 2052, at a redemption price equal to 100% of the principal amount thereof plus a “make-whole” premium and accrued and unpaid interest thereon to the date of redemption, and (ii) at any time on and after July 6, 2052, at 100% of the principal amount thereof plus accrued and unpaid interest thereon to the date of redemption.

The Bond Purchase Agreement also provides for the issuance of $80.0 million aggregate principal amount of NW Natural’s FMBs, 5.18% Series due 2034 (5.18% Bonds) and $50.0 million aggregate principal amount of NW Natural’s FMBs, 5.23% Series due 2038 (5.23% Bonds). The 5.18% Bonds and the 5.23% Bonds are expected to be issued on or about August 4, 2023.

SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF NORTHWEST NATURAL HOLDING COMPANY

NORTHWEST NATURAL HOLDING COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME
(PARENT COMPANY ONLY)

	Year Ended December 31,		
In thousands	2022	2021	2020
Operating expenses:			
Operations and maintenance	$ 3,828	$ 4,837	$ 771
Total operating expenses	3,828	4,837	771
Loss from operations	(3,828)	(4,837)	(771)
Earnings from investment in subsidiaries, net of tax	92,727	83,072	78,450
Other income (expense), net	60	(143)	57
Interest expense, net	4,967	982	1,557
Income before income taxes	83,992	77,110	76,179
Income tax benefit	(2,311)	(1,556)	(602)
Net income	86,303	78,666	76,781
Other comprehensive income (loss) from subsidiaries, net of tax	5,108	1,498	(2,169)
Unrealized gain on interest rate swap, net of tax	11	—	—
Comprehensive income	$ 91,422	$ 80,164	$ 74,612

See Notes to Condensed Financial Statements

NORTHWEST NATURAL HOLDING COMPANY
CONDENSED BALANCE SHEETS
(PARENT COMPANY ONLY)

	As of December 31,	
In thousands	2022	2021
Assets:		
Current assets:		
Cash and cash equivalents	$ 7,280	$ 265
Receivables from affiliates	9,967	2,180
Other current assets	2,895	11,348
Total current assets	20,142	13,793
Non-current assets:		
Investments in subsidiaries	1,357,599	1,080,949
Other investments	14	42
Deferred tax assets	520	383
Other non-current assets	486	613
Total non-current assets	1,358,619	1,081,987
Total assets	$ 1,378,761	$ 1,095,780
Liabilities and equity:		
Current liabilities:		
Short-term debt	$ 88,000	$ 144,000
Accounts payable	402	286
Payables to affiliates	14,665	16,105
Other current liabilities	295	243
Total current liabilities	103,362	160,634
Long-term debt	99,958	—
Total equity	1,175,441	935,146
Total liabilities and equity	$ 1,378,761	$ 1,095,780

See Notes to Condensed Financial Statements

NORTHWEST NATURAL HOLDING COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
(PARENT COMPANY ONLY)

	Year Ended December 31,		
In thousands	2022	2021	2020
Operating activities:			
Net income	$ 86,303	$ 78,666	$ 76,781
Adjustments to reconcile net income to cash used in operations:			
Equity in earnings of subsidiaries, net of tax	(92,727)	(83,072)	(78,450)
Cash dividends received from subsidiaries	62,710	56,057	55,387
Deferred income taxes	(141)	(212)	20
Other	142	119	65
Changes in assets and liabilities:			
Receivables from affiliates	(7,787)	12,558	(12,788)
Income and other taxes	8,161	1,299	(7,451)
Accounts payable	(2,499)	3,342	8,809
Interest accrued	156	57	77
Other, net	(211)	(313)	(364)
Cash provided by operating activities	54,107	68,501	42,086
Investing activities:			
Contributions to subsidiaries	(241,497)	(142,405)	(47,194)
Return of capital from subsidiaries	—	26,000	19,000
Cash used in investing activities	(241,497)	(116,405)	(28,194)
Financing activities:			
Proceeds from common stock issued, net	208,561	17,501	—
Long-term debt issued	100,000	—	—
Changes in other short-term debt, net	(56,000)	71,000	49,000
Cash dividend payments on common stock	(62,771)	(55,919)	(55,420)
Other	4,615	4,320	3,676
Cash provided by (used in) financing activities	194,405	36,902	(2,744)
Increase (decrease) in cash and cash equivalents	7,015	(11,002)	11,148
Cash, cash equivalents and restricted cash, beginning of period	265	11,267	119
Cash, cash equivalents and restricted cash, end of period	$ 7,280	$ 265	$ 11,267

See Notes to Condensed Financial Statements

NOTES TO CONDENSED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION

NW Holdings is an energy services holding company that conducts substantially all of its business operations through its subsidiaries, particularly NW Natural. These condensed financial statements and related footnotes have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X. These financial statements, in which NW Holdings' subsidiaries have been included using the equity method, should be read in conjunction with the consolidated financial statements and notes thereto of NW Holdings included in Item 8 of this Form 10-K.

Equity earnings of subsidiaries including earnings from NW Natural were $92.7 million, $83.1 million, and $78.5 million for the years ended December 31, 2022, 2021, and 2020 respectively.

There were $62.7 million, $82.1 million and $74.4 million of cash dividends paid to NW Holdings from wholly-owned subsidiaries for the years ended December 31, 2022, 2021 and 2020, respectively.

Other Comprehensive Income (Loss) from Subsidiaries Correction

During 2021, NW Holdings identified that activities related to other comprehensive income (loss) from subsidiaries had been excluded from the condensed statements of comprehensive income and condensed balance sheets. NW Holdings corrected the previously presented condensed balance sheet for the year ended December 31, 2020, and in doing so, decreased total equity by $3.6 million with a corresponding decrease in investment in subsidiaries. In addition, the condensed statement of comprehensive income for the year ended December 31, 2020 was corrected to include other comprehensive loss of $2.2 million. NW Holdings has evaluated the effect of the misstatement, both qualitatively and quantitatively, and concluded that it did not have a material impact on, nor require amendment of, any previously filed condensed financial statements.

2. DEBT

For information concerning NW Holdings' debt obligations, see Note 9 to the consolidated financial statements included in Item 8 of this report.

NORTHWEST NATURAL HOLDING COMPANY

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN B	COLUMN C		COLUMN D	COLUMN E
		Additions		Deductions	
In thousands (year ended December 31)	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts	Net write-offs	Balance at end of period
2022					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 2,018	$ 1,081	$ 1,810	$ 1,613	$ 3,296
2021					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 3,219	$ 724	$ (219)	$ 1,706	$ 2,018
2020					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 673	$ 890	$ 2,333	$ 677	$ 3,219

NORTHWEST NATURAL GAS COMPANY

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN B	COLUMN C		COLUMN D	COLUMN E
		Additions		Deductions	
In thousands (year ended December 31)	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts	Net write-offs	Balance at end of period
2022					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 1,962	$ 920	$ 1,810	$ 1,613	$ 3,079
2021					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 3,107	$ 780	$ (219)	$ 1,706	$ 1,962
2020					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 672	$ 779	$ 2,333	$ 677	$ 3,107

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

NW Holdings and NW Natural management, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, completed an evaluation of the effectiveness of the design and operation of disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act)). Based upon this evaluation, the Chief Executive Officer and Chief Financial Officer of each registrant have concluded that, as of the end of the period covered by this report, disclosure controls and procedures were effective to ensure that information required to be disclosed by each such registrant and included in reports filed or submitted under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission (SEC) rules and forms and that such information is accumulated and communicated to management of each registrant, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control Over Financial Reporting

NW Holdings and NW Natural management are responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the Exchange Act Rule 13a-15(f).

In September 2022, we implemented a new enterprise resource planning system to replace our legacy system. The implementation was designed to increase the automation of internal controls in areas of purchasing and payables, asset management, financial reporting and consolidation and to improve access security. In connection with this implementation, we performed pre-implementation planning, design and testing of internal controls that became effective in the third quarter of 2022. Management has and will continue to evaluate and monitor NW Holdings' and NW Natural's internal controls over financial reporting to verify such controls remain effective as processes and procedures in each of the affected areas continue to evolve.

There were no other changes in NW Holdings' or NW Natural's internal control over financial reporting during the quarter ended December 31, 2022 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting for NW Holdings and NW Natural. The statements contained in Exhibit 31.1, Exhibit 31.2, Exhibit 31.3, and Exhibit 31.4 should be considered in light of, and read together with, the information set forth in this Item 9(a).

ITEM 9B. OTHER INFORMATION

On February 23, 2023, the Board of Directors of NW Natural approved Amended and Restated Change in Control Severance Agreements (Amended Agreements) with each of David H. Anderson, NW Natural's Chief Executive Office, Frank H. Burkhartsmeyer, NW Natural's Chief Financial Officer, and each of NW Natural's other named executive officers, which amend and restate the existing Change of Control Agreements (Existing Agreements) with each of those officers. The Amended Agreements, like the Existing Agreements are "double-trigger" and become payable only upon the occurrence of a Change of Control and either (i) the officer's employment is terminated without Cause or for Disability after the earlier of Shareholder Approval, if applicable, or the Change of Control and no later than twenty-four (24) months after the Change of Control; or (ii) the officer delivers a notice of termination for Good Reason after the earlier of Shareholder Approval, if applicable, or the Change of Control and no later than twenty-four (24) months after the Change of Control. The Amended Agreements amend the Existing Agreements in the following ways:

- utilizes the target payment under the Executive Annual Incentive Compensation Plan, rather than the average of the last three years' bonus in calculating the severance payment;
- adjusted health and welfare benefits from 24 months to 30 months for Mr. Anderson to align with the time period of his severance payment;
- adjusts vacation provision language to reflect that NW Natural no longer cashes out vacation;
- clarifies that a Change in Control will not be triggered with the aggregation of above 20% of Voting Securities, provided the acquirer of such Voting Securities has filed a Schedule 13G indicating that the Voting Securities are not acquired and are not held for the purpose of or with the effect of changing management or policies;
- contains other clarifying provisions.

The foregoing description is qualified in its entirety by the full forms of agreement, which are filed as Exhibits 10o and 10p to this Form 10-K. Capitalized terms not defined herein shall have the meanings set forth in the Amended Agreements.

On February 22, 2023, the Organization and Executive Compensation Committees of the Boards of Directors of NW Holding and NW Natural (OECC) approved amendments to the February 2021 and February 2022 Performance Share Long Term Incentive

Agreements (LTIP Agreements) with the same officers such that, if the officers become entitled to receive severance benefits as described above in connection with the Amended Agreements, the shares of Common Stock subject to the LTIP Agreements will fully vest based on target performance. The foregoing description is qualified in its entirety by the full form of amendment, which is filed as Exhibit 10w to this Form 10-K.

On February 23, 2023, the Board of Directors of NW Holdings and NW Natural approved amendments to the Executive Annual Incentive Plan (EAIP) to provide that if an officer becomes entitled to receive change of control severance benefits as described above in connection with the Amended Agreements, he or she will receive a pro-rated award under the EAIP based on days worked during the year relative to target performance. The amendment also provides that if there is a change of control and the participant remains employed through the end of the performance period, he or she will receive payment at target. The foregoing description is qualified in its entirety by the full form of the amended EAIP, which is filed as Exhibit 10m to this Form 10-K.

On February 22, 2023, the OECCs granted performance share awards to the each of the same officers. The form of Performance Share Long Term Incentive Agreement pursuant to which the awards were made is substantially the same as the form used for the February 2022 awards, except that they provide for “double-trigger” vesting at target as described above with respect to the amendments to the LTIP Agreements. The foregoing description is qualified in its entirety by the full form of award agreement, which is filed as Exhibit 10x to this Form 10-K.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The "Information Concerning Nominees and Continuing Directors" and "Corporate Governance" contained in NW Holdings' definitive Proxy Statement for the 2023 Annual Meeting of Shareholders is hereby incorporated by reference.

EXECUTIVE OFFICERS

Name	Age at Dec. 31, 2022	Positions held during last five years[1]
David H. Anderson*	61	President and Chief Executive Officer[2] (2016-); Chief Operating Officer and President (2015-2016); Executive Vice President and Chief Operating Officer (2014-2015); Executive Vice President Operations and Regulation (2013-2014); Senior Vice President and Chief Financial Officer (2004-2013).
Frank H. Burkhartsmeyer*	58	Senior Vice President and Chief Financial Officer[2] (2017-); President and Chief Executive Officer of Renewables, Avangrid Renewables (2015-2017); Senior Vice President of Finance, Iberdrola Renewables Holdings, Inc. (2012-2015).
James R. Downing	53	Vice President and Chief Information Officer (2017-); Chief Information Officer, WorleyParsons (America's Division) (2016-2017); Executive Service Delivery Manager for SAP, British Petroleum (2011-2015).
Shawn M. Filippi*	50	Vice President, Chief Compliance Officer and Corporate Secretary[2] (2016-); Vice President and Corporate Secretary (2015-2016); Senior Legal Counsel (2011-2014); Assistant Corporate Secretary (2010-2014).
Kimberly Heiting Rush	53	Senior Vice President, Operations and Chief Marketing Officer (2018-); Senior Vice President, Communications and Chief Marketing Officer (2018); Vice President, Communications and Chief Marketing Officer (2015-2018); Chief Marketing and Communications Officer (2013-2014); Chief Corporate Communications Officer (2011-2013).
Jon G. Huddleston	60	Vice President, Engineering and Utility Operations (2018-); Senior Director, Utility Operations (2014-2018); Director, Utility Operations (2013-2014); Process Director (2007-2013).
Zachary D. Kravitz	39	Vice President, Rates and Regulatory (2022-); Senior Director, Rates and Regulatory (2021-2022); Director, Rates and Regulatory (2018-2021); Regulatory Attorney (2014-2018).
Justin B. Palfreyman	44	President, NW Natural RNG Holding Company, LLC (2021-); Vice President, Strategy and Business Development (2017-); President, NW Natural Water (2018-); Vice President, Business Development (2016-2017); Director, Power, Energy and Infrastructure Group, Lazard, Freres & Co. (2009-2016).
Melinda B. Rogers	57	Vice President, Chief Human Resources and Diversity Officer (2018-); Senior Director of Human Resources (2018); Senior Manager, Organizational Effectiveness and Talent Acquisition (2015-2017); Senior Associate, Point B (2014-2015); Director, Executive Development Center, Willamette University (2011-2014).
MardiLyn Saathoff*	66	Senior Vice President, Regulation and General Counsel[2] (2016-); Senior Vice President and General Counsel (2015-2016); Vice President, Legal, Risk and Compliance (2013-2014); Deputy General Counsel (2010-2013); Chief Governance Officer and Corporate Secretary (2008-2014).
David A. Weber	63	Vice President, Gas Supply and Utility Support Services (2019-); President and Chief Executive Officer, NW Natural Gas Storage, LLC (2011-); President, KB Pipeline Company (2018-); President and Chief Executive Officer, Gill Ranch Storage, LLC (2011-2020).
Kathryn M. Williams	47	Vice President, Public Affairs and Sustainability (2020-); Vice President, Public Affairs (2019-2020); Government and Community Affairs Director (2018-2019); State Affairs Manager, Port of Portland (2015-2018); Business and Rail Relations Manager, Port of Portland (2007-2015).
Brody J. Wilson*	43	Vice President, Chief Accounting Officer, Controller and Treasurer[2] (2017-); Chief Financial Officer (Interim), Treasurer (Interim), Chief Accounting Officer and Controller (2016-2017); Chief Accounting Officer, Controller and Assistant Treasurer (2016); Controller (2013-2016); Acting Controller (2013); Accounting Director (2012-2013).

DIRECTOR (NORTHWEST NATURAL GAS COMPANY ONLY)**		
Name	Age at Dec. 31, 2022	Positions held during last five years(1)
Steven E. Wynne**	70	Executive Vice President, Moda, Inc., a privately-held healthcare insurance company (2012-); Director, JELD-WEN Holding Inc. (2012-); Director, Pendleton Woolen Mills, Inc. (2013-); Director, Lone Rock Resources, Inc. (2016-); Director, FLIR Systems, Inc. (1999-2021); Director, Citifyd Inc. (2013-2019); Trustee, Willamette University (1999-); Trustee, Portland Center Stage (2012-2019); Executive Vice President, JELD-WEN, Inc. (2011-2012); President and Chief Executive Officer, SBI International, Ltd. (2004-2007); Partner, Ater Wynne LLP (2001-2002; 2003-2004); President and Chief Executive Officer, Adidas America, Inc. (1995-2000). Mr. Wynne's senior management experience with a variety of companies, board service on a number of public and private companies and longstanding legal practice in the areas of corporate finance, securities and mergers and acquisitions qualify him to provide insight and guidance in the areas of corporate governance, strategic planning, enterprise risk management, finance and operations.

* Executive Officer of Northwest Natural Holding Company and Northwest Natural Gas Company.
** Director of Northwest Natural Gas Company only (beginning 2018). All other directors of Northwest Natural Gas Company are also directors of Northwest Natural Holding Company, and information regarding all directors concurrently serving on the Board of Directors of Northwest Natural Gas Company and Northwest Natural Holding Company will be incorporated by reference to our definitive Proxy Statement for the 2023 Annual Meeting of Shareholders.
(1) Unless otherwise specified, all positions held at Northwest Natural Gas Company.
(2) Position held at Northwest Natural Holding Company (beginning March 2018) and Northwest Natural Gas Company. In 2020, Ms. Saathoff's title at Northwest Natural Holding Company changed from Senior Vice President and General Counsel to Senior Vice President, Regulation and General Counsel.

Each executive officer serves successive annual terms; present terms end at the first meeting of the Board of Directors after the 2023 Annual Meeting of Shareholders. There are no family relationships among our executive officers, directors or any person chosen to become one of our officers or directors. NW Holdings and NW Natural have adopted a Code of Ethics (Code) applicable to all employees, officers, and directors that is available on our website at www.nwnaturalholdings.com. We intend to disclose on our website at www.nwnaturalholdings.com any amendments to the Code or waivers of the Code for executive officers and directors.

ITEM 11. EXECUTIVE COMPENSATION

The information concerning "Executive Compensation", "Report of the Organization and Executive Compensation Committee", and "Compensation Committee Interlocks and Insider Participation" contained in NW Holdings' definitive Proxy Statement for the 2023 Annual Meeting of Shareholders is hereby incorporated by reference. Information related to Executive Officers as of December 31, 2022 is reflected in Part III, Item 10, above.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

As of February 16, 2023, NW Holdings owned 100% of the outstanding common stock of NW Natural.

The following table sets forth information regarding compensation plans under which equity securities of NW Holdings are authorized for issuance as of December 31, 2022 (see Note 8 to the Consolidated Financial Statements):

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders:			
Long Term Incentive Plan (LTIP) (1)(2)	242,128	n/a	247,666
Employee Stock Purchase Plan	41,558	$ 39.67	278,219
Equity compensation plans not approved by security holders:			
Executive Deferred Compensation Plan (EDCP)(3)	794	n/a	n/a
Directors Deferred Compensation Plan (DDCP)(3)	30,551	n/a	n/a
Deferred Compensation Plan for Directors and Executives (DCP)(4)	191,781	n/a	n/a
Total	506,812		525,885

(1) Awards may be granted under the LTIP as Performance Share Awards, Restricted Stock Units, or stock options. Shares issued pursuant to Performance Share Awards and Restricted Stock Units under the LTIP do not include an exercise price, but are payable when the award criteria are satisfied. The number of shares shown in column (a) include 99,848 Restricted Stock Units and 142,280 Performance Share Awards, reflecting the number of shares to be issued as performance share awards under outstanding Performance Share Awards if target performance levels are achieved. If the maximum awards were paid pursuant to the Performance Share Awards outstanding at December 31, 2022, the number of shares shown in column (a) would increase by 142,280 shares, reflecting the maximum share award of 200% of target, and the number of shares shown in column (c) would decrease by the same amount of shares. No stock options or other types of award have been issued under the LTIP.

(2) The number of shares shown in column (c) includes shares that are available for future issuance under the LTIP as Restricted Stock Units or Performance Share Awards at December 31, 2022.

(3) Prior to January 1, 2005, deferred amounts were credited, at the participant's election, to either a “cash account” or a “stock account.” If deferred amounts were credited to stock accounts, such accounts were credited with a number of shares of NW Natural (now NW Holdings) common stock based on the purchase price of the common stock on the next purchase date under our Dividend Reinvestment and Direct Stock Purchase Plan, and such accounts were credited with additional shares based on the deemed reinvestment of dividends. Cash accounts are credited quarterly with interest at a rate equal to Moody's Average Corporate Bond Yield plus two percentage points, subject to a 6% minimum rate. At the election of the participant, deferred balances in the stock accounts are payable after termination of Board service or employment in a lump sum, in installments over a period not to exceed 10 years in the case of the DDCP, or 15 years in the case of the EDCP, or in a combination of lump sum and installments. Amounts credited to stock accounts are payable solely in shares of common stock and cash for fractional shares, and amounts in the above table represent the aggregate number of shares credited to participant's stock accounts. We have contributed common stock to the trustee of the Umbrella Trusts such that the Umbrella Trusts hold approximately the number of shares of common stock equal to the number of shares credited to all participants' stock accounts.

(4) Effective January 1, 2005, the EDCP and DDCP were closed to new participants and replaced with the DCP. The DCP continues the basic provisions of the EDCP and DDCP under which deferred amounts are credited to either a “cash account” or a “stock account.” Stock accounts represent a right to receive shares of NW Holdings common stock on a deferred basis, and such accounts are credited with additional shares based on the deemed reinvestment of dividends. Effective January 1, 2007, cash accounts are credited quarterly with interest at a rate equal to Moody's Average Corporate Bond Yield. Our obligation to pay deferred compensation in accordance with the terms of the DCP will generally become due on a predetermined date during a participant's service if elected by such participant or on retirement, death, or other termination of service, and will be paid in a lump sum or in installments of five, 10, or 15 years as elected by the participant in accordance with the terms of the DCP. Amounts credited to stock accounts are payable solely in shares of common stock and cash for fractional shares, and amounts in the above table represent the aggregate number of shares credited to participants' stock accounts. We have contributed common stock to the trustee of the Supplemental Trust such that this trust holds approximately the number of common shares equal to the number of shares credited to all participants' stock accounts. The right of each participant in the DCP is that of a general, unsecured creditor of NW Natural.

The information captioned “Beneficial Ownership of Common Stock by Directors and Executive Officers” and "Security Ownership of Common Stock of Certain Beneficial Owners" contained in NW Holdings' definitive Proxy Statement for the 2023 Annual Meeting of Shareholders is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information captioned "Transactions with Related Persons" and "Corporate Governance" in NW Holdings' definitive Proxy Statement for the 2023 Annual Meeting of Shareholders is hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

NW Holdings
The information captioned "2022 and 2021 Audit Firm Fees" in NW Holdings' definitive Proxy Statement for the 2023 Annual Meeting of Shareholders is hereby incorporated by reference.

NW Natural
The following table shows the fees and expenses of NW Natural, paid or accrued for the integrated audits of the consolidated financial statements and other services provided by NW Natural's independent registered public accounting firm, PricewaterhouseCoopers LLP, for fiscal years 2022 and 2021:

In thousands	2022	2021
Audit Fees	$ 1,518	$ 1,268
Audit-Related Fees	477	172
Tax Fees	23	23
All Other Fees	4	4
Total	$ 2,022	$ 1,467

AUDIT FEES. This category includes fees and expenses for services rendered for the integrated audit of the consolidated financial statements included in the Annual Report on Form 10-K and the review of the quarterly financial statements included in the Quarterly Reports on Form 10-Q. The integrated audit includes the review of our internal control over financial reporting in compliance with Section 404 of the Sarbanes-Oxley Act of 2002 (Sarbanes-Oxley Act). In addition, amounts include fees for services routinely provided by the auditor in connection with regulatory filings, including issuance of consents and comfort letters relating to the registration of Company securities and assistance with the review of documents filed with the SEC.

AUDIT-RELATED FEES. This category includes fees for assurance and related services that are reasonably related to the performance of the audit or review of our financial statements and internal control over financial reporting, including fees and expenses related to consultations for financial accounting and reporting, fees for EPA assurance letters, and fees for system pre-implementation assessments.

TAX FEES. This category includes fees for tax compliance, and review services rendered for NW Natural's income tax returns.

ALL OTHER FEES. This category relates to services other than those described above. The amount reflects payments for accounting research tools in each of 2022 and 2021.

PRE-APPROVAL POLICY FOR AUDIT AND NON-AUDIT SERVICES. The Audit Committee of NW Natural approved or ratified 100 percent of 2022 and 2021 services for audit, audit-related, tax services and all other fees, including audit services relating to compliance with Section 404 of the Sarbanes-Oxley Act. The chair of the Audit Committee of NW Natural is authorized to pre-approve non-audit services between meetings of the Audit Committee and must report such approvals at the next Audit Committee meeting.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as part of this report:

1. A list of all Financial Statements and Supplemental Schedules is incorporated by reference to Item 8.

2. List of Exhibits filed:

   Reference is made to the Exhibit Index commencing on page 142.

ITEM 16. FORM 10-K SUMMARY

None.

NORTHWEST NATURAL HOLDING COMPANY
NORTHWEST NATURAL GAS COMPANY

Exhibit Index to Annual Report on Form 10-K
For the Fiscal Year Ended December 31, 2022

Exhibit Number	Document
*3a.	Amended and Restated Articles of Incorporation of Northwest Natural Holding Company (incorporated by reference to Exhibit 3.1 to the Form 8-K dated October 1, 2018, File No. 1-38681).
*3b.	Amended and Restated Articles of Incorporation of Northwest Natural Gas Company (incorporated by reference to Exhibit 3b to Form 10-K for the year ended December 31, 2020).
*3c.	Amended and Restated Bylaws of Northwest Natural Holding Company (incorporated by reference to Exhibit 3.1 to the Form 10-Q for the quarter ended June 30, 2022, File No. 1-38681).
*3d.	Amended and Restated Bylaws of Northwest Natural Gas Company (incorporated by reference to Exhibit 3.2 to the Form 10-Q for the quarter ended June 30, 2022, File No. 1-38681).
*4a.	Copy of Mortgage and Deed of Trust of Northwest Natural Gas Company, dated as of July 1, 1946 (Mortgage and Deed of Trust), to Bankers Trust (to whom Deutsche Bank Trust Company Americas is the successor), Trustee (incorporated by reference to Exhibit 7(j) in File No. 2-6494); and copies of Supplemental Indentures Nos. 1 through 14 to the Mortgage and Deed of Trust, dated respectively, as of June 1, 1949, March 1, 1954, April 1, 1956, February 1, 1959, July 1, 1961, January 1, 1964, March 1, 1966, December 1, 1969, April 1, 1971, January 1, 1975, December 1, 1975, July 1, 1981, June 1, 1985 and November 1, 1985 (incorporated by reference to Exhibit 4(d) in File No. 33-1929); Supplemental Indenture No. 15 to the Mortgage and Deed of Trust, dated as of July 1, 1986 (filed as Exhibit 4(c) in File No. 33-24168); Supplemental Indentures Nos. 16, 17 and 18 to the Mortgage and Deed of Trust, dated, respectively, as of November 1, 1988, October 1, 1989 and July 1, 1990 (incorporated by reference to Exhibit 4(c) in File No. 33-40482); Supplemental Indenture No. 19 to the Mortgage and Deed of Trust, dated as of June 1, 1991 (incorporated by reference to Exhibit 4(c) in File No. 33-64014).
*4b.	Supplemental Indenture No. 20 to the Mortgage and Deed of Trust, dated as of June 1, 1993 (incorporated by reference to Exhibit 4a.(1) to Form 10-K for year ended December 31, 1993, File No. 0-00994).
*4c.	Supplemental Indenture No. 21 to the Mortgage and Deed of Trust, dated as of October 15, 2012 (incorporated by reference to Exhibit 4.1 to Form 8-K dated October 26, 2012, File No. 1-15973).
*4d.	Supplemental Indenture No. 22 to the Mortgage and Deed of Trust, dated as of November 1, 2016 (incorporated by reference to Exhibit 4.1 to Form 10-Q for the quarter ended September 30, 2016, File No. 1-15973).
*4e.	Supplemental Indenture No. 23 to the Mortgage and Deed of Trust, dated as of September 1, 2018 (incorporated by reference to Exhibit 4(a) to Form 8-K dated September 10, 2018, File No. 1-15973).
*4f.	Twenty-fourth Supplemental Indenture, providing for, among other things, First Mortgage Bonds, 4.78% Series due 2052, dated as of September 1, 2022, by and between Northwest Natural Gas Company and Deutsche Bank Trust Company Americas (incorporated by reference to Exhibit 4.1 to the Form 8-K filed September 30, 2022, file No. 1-15973).
*4g.	Twenty-fifth Supplemental Indenture, providing for, among other things, First Mortgage Bonds, 5.43% Series due 2053, dated as of December 1, 2022, by and between Northwest Natural Gas Company and Deutsche Bank Trust Company Americas (incorporated by reference to Exhibit 4.1 to Form 8-K dated December 1, 2022, File No. 1-15973).
*4h.	Copy of Indenture, dated as of June 1, 1991, between Northwest Natural Gas Company and Bankers Trust Company (to whom Deutsche Bank Trust Company Americas is successor), Trustee, relating to Northwest Natural Gas Company's Unsecured Debt Securities (incorporated by reference to Exhibit 4(e) in File No. 33-64014).

4i.	Amended and Restated Credit Agreement, dated as of November 3, 2021, among Northwest Natural Holding Company and the lenders party thereto, with JPMorgan Chase Bank, N.A. as administrative agent and Bank of America, N.A., U.S. Bank National Association, and Wells Fargo Bank, National Association, as co-syndication agents, as amended by Amendment No.1, dated as of January 20, 2023.
4j.	Amended and Restated Credit Agreement, dated as of November 3, 2021, among Northwest Natural Gas Company and the lenders party thereto, with JPMorgan Chase Bank, N.A. as administrative agent and Bank of America, N.A., U.S. Bank National Association, and Wells Fargo Bank, National Association, as co-syndication agents, as amended by Amendment No. 1, dated as of January 20, 2023.
*4k.	Credit Agreement, dated as of June 10, 2021, among NW Natural Water Company, LLC, Northwest Natural Holding Company, the lenders party thereto, and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 4.2 to the Form 8-K filed June 14, 2021, File No. 1-38681).
*4l.	Credit Agreement, dated as of June 10, 2021, among Northwest Natural Gas Company, the lenders party thereto, and U.S. Bank National Association, as administrative agent (incorporated by reference to Exhibit 4.1 to the Form 8-K filed June 14, 2021, File No. 1-15973).
*4m.	Credit Agreement, dated as of September 15, 2022, among Northwest Natural Holding Company and the lenders party thereto, with U.S. Bank National Association as administrative agent (incorporated by reference to Exhibit 4.1 to the Form 8-K filed September 21, 2022, file No. 1-38681).
*4n.	Credit Agreement, dated as of September 15, 2022, among NW Natural Water Company, LLC, Northwest Natural Holding Company and the lenders party thereto, with U.S. Bank National Association as administrative agent (incorporated by reference to Exhibit 4.2 to the Form 8-K filed September 21, 2022, file No. 1-38681).
*4o.	Description of securities registered under Section 12 of the Exchange Act of 1934 (incorporated by reference to Exhibit 4j to Form 10-K for the year ended December 31, 2019, File No. 1-38681).
*10	Purchase and Sale Agreement dated June 20, 2018, between NW Natural Gas Storage LLC and SENSA Holdings LLC (incorporated by reference to Exhibit 10 to Form 10-Q for the quarter ended June 30, 2018, File No. 1-15973).
*10.1	Fifth Amendment to Purchase and Sale Agreement, dated April 29, 2020, between NW Natural Gas Storage, LLC and SENSA Holdings LLC, amending the Purchase and Sale Agreement, dated June 20, 2018, as amended (incorporated by reference to Exhibit 10.2 to the Form 10-Q for the quarter ended March 31, 2020, File No. 1-38681).
*10.2	Tenth Amendment to Purchase and Sale Agreement, dated December 4, 2020, between NW Natural Gas Storage LLC and SENSA Holdings LLC, amending the Purchase and Sale Agreement, dated June 20, 2018, as amended (incorporated by reference to Exhibit 10.1 to the Form 8-K filed December 7, 2020, File No. 1-38681).
21	Subsidiaries of Northwest Natural Holding Company.
23a.	Consent of PricewaterhouseCoopers LLP - NW Holdings.
23b.	Consent of PricewaterhouseCoopers LLP - NW Natural.
31.1	Certification of Principal Executive Officer of Northwest Natural Gas Company Pursuant to Rule 13a-14(a)/15d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer of Northwest Natural Gas Company Pursuant to Rule 13a-14(a)/15d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
31.3	Certification of Principal Executive Officer of Northwest Natural Holding Company Pursuant to Rule 13a-14(a)/15d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
31.4	Certification of Principal Financial Officer of Northwest Natural Holding Company Pursuant to Rule 13a-14(a)/15d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.

**32.1	Certification of Principal Executive Officer and Principal Financial Officer of Northwest Natural Gas Company Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**32.2	Certification of Principal Executive Officer and Principal Financial Officer of Northwest Natural Holding Company Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.	The following materials formatted in Inline Extensible Business Reporting Language (Inline XBRL): (i) Consolidated Statements of Income; (ii) Consolidated Balance Sheets; (iii) Consolidated Statements of Cash Flows; and (iv) Related notes.
104.	The cover page from the Company's Annual Report on Form 10-K for the year ended December 31, 2021, formatted in Inline XBRL and contained in Exhibit 101.

Executive Compensation Plans and Arrangements:

*10a.	Executive Supplemental Retirement Income Plan, 2018 Restatement (incorporated herein by reference to Exhibit 10.6 to the Form 8-K dated October 1, 2018, File No. 1-38681).
*10b.	Supplemental Executive Retirement Plan of Northwest Natural Gas Company, 2018 Restatement, as amended July 25, 2019 (incorporated by reference to Exhibit 10.1 to the Form 10-Q for the quarter ended June 30, 2019, File No. 1-15973).
*10c.	Northwest Natural Gas Company Supplemental Trust, effective January 1, 2005, restated as of October 1, 2018 (incorporated by reference to Exhibit 10.9 to the Form 8-K dated October 1, 2018, File No. 1-38681).
*10d.	Northwest Natural Gas Company Umbrella Trust for Directors, effective January 1, 1991, restated as of October 1, 2018 (incorporated by reference to Exhibit 10.11 to the Form 8-K dated October 1, 2018, File No. 1-38681).
*10e.	Northwest Natural Gas Company Umbrella Trust for Executives, effective January 1, 1988, restated as of October 1, 2018 (incorporated by reference to Exhibit 10.10 to the Form 8-K dated October 1, 2018, File No. 1-38681).
*10f.	Executive Deferred Compensation Plan, effective as of January 1, 1987, restated as of October 1, 2018 (incorporated by reference to Exhibit 10.4 to the Form 8-K dated October 1, 2018, File No. 1-38681).
*10g.	Directors Deferred Compensation Plan, effective June 1, 1981, restated as of October 1, 2018 (incorporated by reference to Exhibit 10.5 to the Form 8-K dated October 1, 2018, File No. 1-38681).
*10h.	Deferred Compensation Plan for Directors and Executives, effective January 1, 2005, restated as of September 23, 2021 (incorporated by reference to Exhibit 10.1 to the Form 10-Q for the quarter ended September 30, 2021, File No. 1-38681).
*10i.	Form of Indemnity Agreement as entered into between Northwest Natural Gas Company and each director and certain executive officers (incorporated by reference to Exhibit 10l to Form 10-K for 2018, File No. 1-15973).
*10j.	Form of Indemnity Agreement as entered into between Northwest Natural Holding Company and each director and certain executive officers (incorporated by reference to Exhibit 10m to Form 10-K for 2018, File No. 1-38681).
*10k.	Non-Employee Directors Stock Compensation Plan, as amended effective December 15, 2005 (incorporated by reference to Exhibit 10.2 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10l.	Executive Annual Incentive Plan, effective January 1, 2022 (incorporated by reference to Exhibit 10o to Form 10-K for 2021, File No. 1-15973).

10m.	Executive Annual Incentive Plan, effective February 23, 2023.
*10n.	Form of Change in Control Severance Agreement between Northwest Natural Gas Company and each executive officer, as amended and restated as of March 1, 2020 (incorporated by reference to Exhibit 10q to Form 10-K for 2019, File No. 1-15973).
10o.	Form of Change in Control Severance Agreement between Northwest Natural Gas Company and David Anderson, as amended and restated as of February 23, 2023.
10p.	Form of Change in Control Severance Agreement between Northwest Natural Gas Company and each executive officer (other than David Anderson), as amended and restated as of February 23, 2023.
*10q.	Northwest Natural Gas Company Long Term Incentive Plan, as amended and restated effective May 25, 2017 (incorporated by reference to Exhibit 10s to Form 10-K for 2017, File No. 1-15973).
*10r.	Northwest Natural Gas Company Long Term Incentive Plan, as amended and restated as of October 1, 2018 (incorporated by reference to Exhibit 10.1 to Form 8-K dated October 1, 2018, File No. 1-38681).
10s.	Northwest Natural Holding Company Long Term Incentive Plan, as amended and restated as of February 23, 2023.
*10t.	Form of Performance Share Long Term Incentive Agreement under Long Term Incentive Plan (2020-2022) (incorporated by reference to Exhibit 10x to Form 10-K for 2019, File No. 1-38681).
*10u.	Form of Performance Share Long Term Incentive Agreement under Long Term Incentive Plan (2021-2023)(incorporated by reference to Exhibit 10w to Form 10-K for 2020, File No. 1-38681).
*10v.	Form of Performance Share Long Term Incentive Agreement under Long Term Incentive Plan (2022-2024) (incorporated by reference to Exhibit 10w to Form 10-K for 2021, File No. 1-38681).
10w.	Form of Amendment to Performance Share Long Term Incentive Agreement under Long Term Incentive Plan (2021-2023) and Long Term Incentive Plan (2022-2024)
10x.	Form of Performance Share Long Term Incentive Agreement under Long Term Incentive Plan (2023-2025).
*10y.	Form of Consent dated December 14, 2006 entered into by each executive officer with respect to amendments to the Executive Supplemental Retirement Income Plan, the Supplemental Executive Retirement Plan and certain change in control severance agreements (incorporated by reference to Exhibit 10.1 to Form 8-K dated December 19, 2006, File No. 1-15973).
*10z.	Consent to Amendment of Deferred Compensation Plan for Directors and Executives, dated February 28, 2008 entered into by each executive officer (incorporated by reference to Exhibit 10bb to Form 10-K for 2007, File No. 1-15973).
*10aa.	Form of Restricted Stock Unit Award Agreement under Long Term Incentive Plan (2022) (incorporated by reference to Exhibit 10z to Form 10-K for 2021, File No. 1-38681).
10bb.	Form of Restricted Stock Unit Award Agreement under Long Term Incentive Plan (2023).
*10cc.	Form of Restricted Stock Unit Award Agreement under Long Term Incentive Plan (2021) (incorporated by reference to Exhibit 10z to Form 10-K for 2020, File No. 1-38681).
*10dd.	Form of Restricted Stock Unit Award Agreement under Long Term Incentive Plan (2020) (incorporated by reference to Exhibit 10aa to Form 10-K for 2019, File No. 1-38681).
*10ee.	Form of Restricted Stock Unit Award Agreement under Long Term Incentive Plan (2019) (incorporated by reference to Exhibit 10cc to Form 10-K for 2018, File No. 1-38681).

*10ff.	Severance Agreement between Northwest Natural Gas Company and an executive officer, dated August 1, 2016 (incorporated by reference to Exhibit 10.1 to Form 8-K dated July 29, 2016, File No. 1-15973).
*10gg.	Form of Severance Agreement between Northwest Natural Gas Company and an executive officer, dated May 17, 2017 (incorporated by reference to Exhibit 10.1 to Form 8-K dated April 24, 2017, File No. 1-15973).
*10hh.	Cash Retention Agreement between Northwest Natural Gas Company and an executive officer, dated as of March 1, 2018 (incorporated by reference to Exhibit 10ss to Form 10-K for 2017, File No. 1-15973).
*10ii.	Annual Incentive Plan for NW Natural Gas Storage, LLC, as amended effective January 1, 2022 (incorporated by reference to Exhibit 10ll to Form 10-K for 2021, File No. 1-38681).

*Incorporated by reference as indicated
**Pursuant to Item 601(b)(32)(ii) of Regulation S-K, this certificate is not being "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature for each undersigned company shall be deemed to relate only to matters having reference to such company and its subsidiaries.

NORTHWEST NATURAL HOLDING COMPANY

By: /s/ David H. Anderson
David H. Anderson
President and Chief Executive Officer
Date: February 24, 2023

NORTHWEST NATURAL GAS COMPANY

By: /s/ David H. Anderson
David H. Anderson
President and Chief Executive Officer
Date: February 24, 2023

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated. The signatures of each of the undersigned shall be deemed to relate only to matters having reference to the below named company and its subsidiaries.

NORTHWEST NATURAL HOLDING COMPANY

Signature	Title	Date
/s/ David H. Anderson David H. Anderson President and Chief Executive Officer	Principal Executive Officer and Director	February 24, 2023
/s/ Frank H. Burkhartsmeyer Frank H. Burkhartsmeyer Senior Vice President and Chief Financial Officer	Principal Financial Officer	February 24, 2023
/s/ Brody J. Wilson Brody J. Wilson Vice President, Treasurer, Chief Accounting Officer and Controller	Principal Accounting Officer	February 24, 2023
/s/ Timothy P. Boyle Timothy P. Boyle	Director	)
/s/ Monica Enand Monica Enand	Director	)
/s/ Karen Lee Karen Lee	Director	)
/s/ Dave McCurdy Dave McCurdy	Director	)
/s/ Sandra McDonough Sandra McDonough	Director	February 24, 2023
/s/ Nathan I. Partain Nathan I. Partain	Director	)
/s/ Jane L. Peverett Jane L. Peverett	Director	)
/s/ Kenneth Thrasher Kenneth Thrasher	Director	)
/s/ Malia H. Wasson Malia H. Wasson	Director	)
/s/ Charles A. Wilhoite Charles A. Wilhoite	Director	)

NORTHWEST NATURAL GAS COMPANY

Signature	Title	Date
/s/ David H. Anderson David H. Anderson President and Chief Executive Officer	Principal Executive Officer and Director	February 24, 2023
/s/ Frank H. Burkhartsmeyer Frank H. Burkhartsmeyer Senior Vice President and Chief Financial Officer	Principal Financial Officer	February 24, 2023
/s/ Brody J. Wilson Brody J. Wilson Vice President, Treasurer, Chief Accounting Officer and Controller	Principal Accounting Officer	February 24, 2023
/s/ Timothy P. Boyle Timothy P. Boyle	Director	)
/s/ Monica Enand Monica Enand	Director	)
/s/ Karen Lee Karen Lee	Director	)
/s/ Dave McCurdy Dave McCurdy	Director	)
/s/ Sandra McDonough Sandra McDonough	Director	February 24, 2023
/s/ Nathan I. Partain Nathan I. Partain	Director	)
/s/ Jane L. Peverett Jane L. Peverett	Director	)
/s/ Kenneth Thrasher Kenneth Thrasher	Director	)
/s/ Malia H. Wasson Malia H. Wasson	Director	)
/s/ Charles A. Wilhoite Charles A. Wilhoite	Director	)
/s/ Steven E. Wynne Steven E. Wynne	Director	)

EXHIBIT A CONFORMED THROUGH AMENDMENT NO. 1
DATED JANUARY 1, 2023

EXECUTION VERSION

J.P.Morgan

AMENDED AND RESTATED CREDIT AGREEMENT

dated as of

November 3, 2021

among

NORTHWEST NATURAL HOLDING COMPANY,

The Lenders Party Hereto

JPMORGAN CHASE BANK, N.A.
as Administrative Agent

BANK OF AMERICA, N.A.,
U.S. BANK NATIONAL ASSOCIATION
and
WELLS FARGO BANK, NATIONAL ASSOCIATION,
as Co-Syndication Agents

J.P. MORGAN SECURITIES LLC,
as Sustainability Structuring Agent
JPMORGAN CHASE BANK, N.A.,
BOFA SECURITIES, INC.,
U.S. BANK NATIONAL ASSOCIATION and WELLS FARGO SECURITIES, LLC,
as Joint Bookrunners and Co-Lead Arrangers

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AMENDED AND RESTATED CREDIT AGREEMENT (this "Agreement") dated as of November 3, 2021 among NORTHWEST NATURAL HOLDING COMPANY, the LENDERS from time to time party hereto, JPMORGAN CHASE BANK, N.A., as Administrative Agent, and BANK OF AMERICA, N.A., U.S. BANK NATIONAL ASSOCIATION and WELLS FARGO BANK, NATIONAL ASSOCIATION, as Co-Syndication Agents.

WHEREAS, the Borrower, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent thereunder, are currently party to that certain Credit Agreement, dated as of October 2, 2018 (as amended, supplemented or otherwise modified prior to the Restatement Effective Date, the "Existing Credit Agreement");

WHEREAS, the Borrower, the Lenders party hereto and the Administrative Agent have agreed to enter into this Agreement in order to (i) amend and restate the Existing Credit Agreement in its entirety, (ii) extend the maturity date in respect of the existing revolving credit facility under the Existing Credit Agreement, (iii) re-evidence the "Obligations" under, and as defined in, the Existing Credit Agreement, which shall be repayable in accordance with the terms of this Agreement, and (iv) set forth the terms and conditions under which the Lenders will, from time to time, make loans and extend other financial accommodations to or for the benefit of the Borrower;

WHEREAS, it is the intent of the parties hereto that this Agreement not constitute a novation of the obligations and liabilities of the parties under the Existing Credit Agreement or be deemed to evidence or constitute full repayment of such obligations and liabilities, but that this Agreement amend and restate in its entirety the Existing Credit Agreement and re-evidence the obligations and liabilities of the Borrower outstanding thereunder, which shall be payable in accordance with the terms hereof; and

WHEREAS, it is also the intent of the Borrower to confirm that all obligations under the applicable "Loan Documents" (as referred to and defined in the Existing Credit Agreement) shall continue in full force and effect as modified or restated by the Loan Documents (as referred to and defined herein) and that, from and after the Restatement Effective Date, all references to the "Credit Agreement" contained in any such existing "Loan Documents" shall be deemed to refer to this Agreement;

NOW, THEREFORE, in consideration of the premises and the mutual covenants contained herein, the parties hereto agree that the Existing Credit Agreement is hereby amended and restated as follows:

ARTICLE I

Definitions

SECTION 1.01 Defined Terms. As used in this Agreement, the following terms have the meanings specified below:

"ABR", when used in reference to any Loan or Borrowing, refers to whether such Loan, or the Loans comprising such Borrowing, bears interest at a rate determined by reference to the Alternate Base Rate.

"Adjusted Daily Simple SOFR" means an interest rate per annum equal to (a) the Daily Simple SOFR, *plus* (b) 0.10%; provided that if the Adjusted Daily Simple SOFR as so determined would be less than the Floor, such rate shall be deemed to be equal to the Floor for the purposes of this Agreement.

"Adjusted Term SOFR Rate" means, for any Interest Period, an interest rate per annum equal to (a) the Term SOFR Rate for such Interest Period, *plus* (b) 0.10%; provided that if the Adjusted Term SOFR Rate as so determined would be less than the Floor, such rate shall be deemed to be equal to the Floor for the purposes of this Agreement.

"Administrative Agent" means JPMorgan Chase Bank, N.A. (including its branches and affiliates), in its capacity as administrative agent for the Lenders hereunder, and any successor appointed in accordance with Article VIII.

"Administrative Questionnaire" means an Administrative Questionnaire in a form supplied by the Administrative Agent.

"Affected Financial Institution" means (a) any EEA Financial Institution or (b) any UK Financial Institution.

"Affiliate" means, with respect to a specified Person, another Person that directly, or indirectly through one or more intermediaries, Controls or is Controlled by or is under common Control with the Person specified.

"Agent-Related Person" has the meaning assigned to such term in Section 9.03(c).

"Aggregate Commitment" means the aggregate of the Commitments of all of the Lenders, as reduced or increased from time to time pursuant to the terms and conditions hereof. As of the Restatement Effective Date, the Aggregate Commitment is $200,000,000.

"Alternate Base Rate" means, for any day, a rate *per annum* equal to the greatest of (a) the Prime Rate in effect on such day, (b) the NYFRB Rate in effect on such day plus 1/2 of 1% and (c) the Adjusted Term SOFR Rate for a one month Interest Period as published two U.S. Government Securities Business Days prior to such day (or if such day is not a U.S. Government Securities Business Day, the immediately preceding U.S. Government Securities Business Day) plus 1%; provided that for the purpose of this definition, the Adjusted Term SOFR Rate for any day shall be based on the Term SOFR Reference Rate at approximately 5:00 a.m. Chicago time on such day (or any amended publication time for the Term SOFR Reference Rate), as specified by the CME Term SOFR Administrator in the Term SOFR Reference Rate methodology. Any change in the Alternate Base Rate due to a change in the Prime Rate, the NYFRB Rate or the Adjusted Term SOFR Rate shall be effective from and including the effective date of such change in the Prime Rate, the NYFRB Rate or the Adjusted Term SOFR Rate, respectively. If the Alternate Base Rate is being used as an alternate rate of interest pursuant to Section 2.14 (for the avoidance of doubt, only until the Benchmark Replacement has been determined pursuant to Section 2.14(b)), then the Alternate Base Rate shall be the greater of clauses (a) and (b) above and shall be determined without reference to clause (c) above. For the avoidance of doubt, if the Alternate Base Rate as determined pursuant to the foregoing would be less than 1.0%, such rate shall be deemed to be 1.0% for purposes of this Agreement.

"Amendment No. 1" means that certain Amendment No. 1 to Amended and Restated Credit Agreement, dated as of January 20, 2023, among the Borrower, the Administrative Agent and the Lenders party thereto.

"Amendment No. 1 Effective Date" means the date on which each of the conditions set forth in Section 2 of Amendment No. 1 are satisfied (or waived), which date is January 20, 2023.

"Ancillary Document" has the meaning assigned to it in Section 9.06(b).

"Anti-Corruption Laws" means all laws, rules, and regulations of any jurisdiction applicable to the Borrower or any of its Subsidiaries from time to time concerning or relating to money laundering, bribery or corruption.

"Applicable Party" has the meaning assigned to it in Section 8.03(c).

"Applicable Percentage" means, with respect to any Lender, the percentage of the Aggregate Commitment represented by such Lender's Commitment; provided that, in the case of Section 2.21 when a Defaulting Lender shall exist, "Applicable Percentage" shall mean the percentage of the Aggregate Commitment (disregarding any Defaulting Lender's Commitment) represented by such

Lender's Commitment. If the Commitments have terminated or expired, the Applicable Percentages shall be determined based upon the Commitments most recently in effect, giving effect to any assignments and to any Lender's status as a Defaulting Lender at the time of determination.

"Applicable Rate" means, for any day, with respect to any Term Benchmark Loan or any ABR Loan or with respect to the facility fees payable hereunder, as the case may be, the applicable rate per annum set forth below under the caption "Term Benchmark and RFR Spread", "ABR Spread" or "Facility Fee Rate", as the case may be, based upon the Debt Rating applicable on such date:

Pricing Level	Debt Rating:	Term Benchmark and RFR Spread	ABR Spread	Facility Fee Rate
Level I	AA- or higher / Aa3 or higher	0.680%	0.000%	0.070%
Level II	A+ / A1	0.795%	0.000%	0.080%
Level III	A / A2	0.900%	0.000%	0.100%
Level IV	A- / A3	1.000%	0.000%	0.125%
Level V	BBB+ / Baa1	1.075%	0.075%	0.175%
Level VI	BBB or below / Baa2 or below	1.275%	0.275%	0.225%

For purposes of the foregoing, (i) if only one of S&P and Moody's shall have in effect a Debt Rating, the applicable Pricing Level shall be determined by reference to the available rating; (ii) if neither S&P nor Moody's shall have in effect a Debt Rating, the applicable Pricing Level will be set in accordance with Level VI; (iii) if the ratings established or deemed to have been established by Moody's and S&P for the Debt Rating shall fall within different Pricing Levels, the applicable Pricing Level shall be based on the better of the two ratings unless the ratings are not in two adjacent Pricing Levels, in which case the applicable Pricing Level shall be determined by reference to the Pricing Level one level below the Pricing Level corresponding to the better of the two ratings; and (iv) if the Debt Ratings established or deemed to have been established by Moody's and S&P shall be changed, such change shall be effective as of the date on which it is first publicly announced by the applicable rating agency. Each change in Pricing Level shall apply during the period commencing on the effective date of such change and ending on the date immediately preceding the effective date of the next such change.

It is hereby understood and agreed that the "Term Benchmark and RFR Spread" (including with respect to the Letter of Credit fees payable pursuant to Section 2.12(b)(i)) and the "ABR Spread" set forth in the table above shall be adjusted from time to time based upon the Sustainability Rate Adjustment and "Facility Fee Rate" set forth in the table above shall be adjusted from time to time based upon the Sustainability Facility Fee Adjustment, in each case to be calculated and applied as set forth in Section 1.08; provided, that in no event shall the Applicable Rate be less than zero.

"Approved Electronic Platform" has the meaning assigned to it in Section 8.03(a).

"Approved Fund" has the meaning assigned to such term in Section 9.04(b).

"Arrangers" means each of JPMorgan Chase Bank, N.A., BofA Securities, Inc., U.S. Bank National Association and Wells Fargo Securities, LLC, in their respective capacities as joint bookrunners and co-lead arrangers hereunder.

"Assignment and Assumption" means an assignment and assumption entered into by a Lender and an assignee (with the consent of any party whose consent is required by Section 9.04), and accepted by the Administrative Agent, in the form of Exhibit A or any other form (including electronic records generated by the use of an electronic platform) approved by the Administrative Agent.

"Augmenting Lender" has the meaning assigned to such term in Section 2.20.

"Authorized Officer" means the chief executive officer, the president, any vice president, the treasurer or any assistant treasurer of the Borrower.

"Availability Period" means the period from and including the Restatement Effective Date to but excluding the earlier of the Maturity Date and the date of termination of the Commitments.

"Available Tenor" means, as of any date of determination and with respect to the then-current Benchmark, as applicable, any tenor for such Benchmark (or component thereof) or payment period for interest calculated with reference to such Benchmark (or component thereof), as applicable, that is or may be used for determining the length of an Interest Period for any term rate or otherwise, for determining any frequency of making payments of interest calculated pursuant to this Agreement as of such date and not including, for the avoidance of doubt, any tenor for such Benchmark that is then-removed from the definition of "Interest Period" pursuant to clause (e) of Section 2.14.

"Bail-In Action" means the exercise of any Write-Down and Conversion Powers by the applicable Resolution Authority in respect of any liability of an Affected Financial Institution.

"Bail-In Legislation" means (a) with respect to any EEA Member Country implementing Article 55 of Directive 2014/59/EU of the European Parliament and of the Council of the European Union, the implementing law, regulation rule or requirement for such EEA Member Country from time to time which is described in the EU Bail-In Legislation Schedule and (b) with respect to the United Kingdom, Part I of the United Kingdom Banking Act 2009 (as amended from time to time) and any other law, regulation or rule applicable in the United Kingdom relating to the resolution of unsound or failing banks, investment firms or other financial institutions or their affiliates (other than through liquidation, administration or other insolvency proceedings).

"Bankruptcy Event" means, with respect to any Person, such Person becomes the subject of a voluntary or involuntary bankruptcy or insolvency proceeding, or has had a receiver, conservator, trustee, administrator, custodian, assignee for the benefit of creditors or similar Person charged with the reorganization or liquidation of its business appointed for it, or, in the good faith determination of the Administrative Agent, has taken any action in furtherance of, or indicating its consent to, approval of, or acquiescence in, any such proceeding or appointment or has had any order for relief in such proceeding entered in respect thereof, provided that a Bankruptcy Event shall not result solely by virtue of any ownership interest, or the acquisition of any ownership interest, in such Person by a Governmental Authority or instrumentality thereof, unless such ownership interest results in or provides such Person with immunity from the jurisdiction of courts within the United States or from the enforcement of judgments or writs of attachment on its assets or permits such Person (or such Governmental Authority or instrumentality) to reject, repudiate, disavow or disaffirm any contracts or agreements made by such Person.

"Benchmark" means, initially, with respect to any (i) RFR Loan (following a Benchmark Transition Event and Benchmark Replacement Date with respect to the Term SOFR Rate), Daily Simple SOFR or (ii) Term Benchmark Loan, the Term SOFR Rate; provided that if a Benchmark Transition Event and the related Benchmark Replacement Date have occurred with respect to the Daily Simple SOFR or Term SOFR Rate, as applicable, or the then-current Benchmark, then "Benchmark" means the applicable Benchmark Replacement to the extent that such Benchmark Replacement has replaced such prior benchmark rate pursuant to clause (b) of Section 2.14.

"Benchmark Replacement" means, for any Available Tenor, the first alternative set forth in the order below that can be determined by the Administrative Agent for the applicable Benchmark Replacement Date:

(1) the sum of: (a) Daily Simple SOFR and (b) the related Benchmark Replacement Adjustment,

(2) the sum of: (a) the alternate benchmark rate that has been selected by the Administrative Agent and the Borrower as the replacement for the then-current Benchmark for the applicable Corresponding Tenor giving due consideration to (i) any selection or recommendation of a replacement benchmark rate or the mechanism for determining such a rate by the Relevant Governmental Body or (ii) any evolving or then-prevailing market convention for determining a benchmark rate as a replacement for the then-current Benchmark for Dollar-denominated syndicated credit facilities at such time in the United States and (b) the related Benchmark Replacement Adjustment.

If the Benchmark Replacement as determined pursuant to the above would be less than the Floor, the Benchmark Replacement will be deemed to be the Floor for the purposes of this Agreement and the other Loan Documents.

"Benchmark Replacement Adjustment" means, with respect to any replacement of the then-current Benchmark with an Unadjusted Benchmark Replacement for any applicable Interest Period and Available Tenor for any setting of such Unadjusted Benchmark Replacement, the spread adjustment, or method for calculating or determining such spread adjustment, (which may be a positive or negative value or zero) that has been selected by the Administrative Agent and the Borrower for the applicable Corresponding Tenor giving due consideration to (i) any selection or recommendation of a spread adjustment, or method for calculating or determining such spread adjustment, for the replacement of such Benchmark with the applicable Unadjusted Benchmark Replacement by the Relevant Governmental Body on the applicable Benchmark Replacement Date and/or (ii) any evolving or then-prevailing market convention for determining a spread adjustment, or method for calculating or determining such spread adjustment, for the replacement of such Benchmark with the applicable Unadjusted Benchmark Replacement for syndicated credit facilities denominated in Dollars at such time.

"Benchmark Replacement Conforming Changes" means, with respect to any Benchmark Replacement and/or any Term Benchmark Loan, any technical, administrative or operational changes (including changes to the definition of "Alternate Base Rate," the definition of "Business Day," the definition of "U.S. Government Securities Business Day," the definition of "Interest Period," timing and frequency of determining rates and making payments of interest, timing of borrowing requests or prepayment, conversion or continuation notices, length of lookback periods, the applicability of breakage provisions, and other technical, administrative or operational matters) that the Administrative Agent decides may be appropriate to reflect the adoption and implementation of any applicable Benchmark and to permit the administration thereof by the Administrative Agent in a manner substantially consistent with market practice (or, if the Administrative Agent decides that adoption of any portion of such market practice is not administratively feasible or if the Administrative Agent determines that no market practice for the administration of such Benchmark exists, in such other manner of administration as the Administrative Agent decides is reasonably necessary in connection with the administration of this Agreement and the other Loan Documents).

"Benchmark Replacement Date" means, with respect to any Benchmark, the earliest to occur of the following events with respect to such then-current Benchmark:

(1) in the case of clause (1) or (2) of the definition of "Benchmark Transition Event," the later of (a) the date of the public statement or publication of information referenced therein and (b) the date on which the administrator of such Benchmark (or the published component used in the calculation thereof) permanently or indefinitely ceases to provide all Available Tenors of such Benchmark (or such component thereof); or

(2) in the case of clause (3) of the definition of "Benchmark Transition Event," the first date on which such Benchmark (or the published component used in the calculation thereof) has been determined and announced by the regulatory supervisor for the administrator of such Benchmark (or such component thereof) to be no longer representative; provided that such non-representativeness will be determined by reference to the most recent statement or publication

referenced in such clause (3) and even if any Available Tenor of such Benchmark (or such component thereof) continues to be provided on such date.

For the avoidance of doubt, (i) if the event giving rise to the Benchmark Replacement Date occurs on the same day as, but earlier than, the Reference Time in respect of any determination, the Benchmark Replacement Date will be deemed to have occurred prior to the Reference Time for such determination and (ii) the "Benchmark Replacement Date" will be deemed to have occurred in the case of clause (1) or (2) with respect to any Benchmark upon the occurrence of the applicable event or events set forth therein with respect to all then-current Available Tenors of such Benchmark (or the published component used in the calculation thereof).

"Benchmark Transition Event" means, with respect to any Benchmark, the occurrence of one or more of the following events with respect to such then-current Benchmark:

(1) a public statement or publication of information by or on behalf of the administrator of such Benchmark (or the published component used in the calculation thereof) announcing that such administrator has ceased or will cease to provide all Available Tenors of such Benchmark (or such component thereof), permanently or indefinitely, provided that, at the time of such statement or publication, there is no successor administrator that will continue to provide any Available Tenor of such Benchmark (or such component thereof);

(2) a public statement or publication of information by the regulatory supervisor for the administrator of such Benchmark (or the published component used in the calculation thereof), the Federal Reserve Board, the NYFRB, the CME Term SOFR Administrator, an insolvency official with jurisdiction over the administrator for such Benchmark (or such component), a resolution authority with jurisdiction over the administrator for such Benchmark (or such component), in each case, or a court or an entity with similar insolvency or resolution authority over the administrator for such Benchmark (or such component), in each case, which states that the administrator of such Benchmark (or such component) has ceased or will cease to provide all Available Tenors of such Benchmark (or such component thereof) permanently or indefinitely; provided that, at the time of such statement or publication, there is no successor administrator that will continue to provide any Available Tenor of such Benchmark (or such component thereof); or

(3) a public statement or publication of information by the regulatory supervisor for the administrator of such Benchmark (or the published component used in the calculation thereof) announcing that all Available Tenors of such Benchmark (or such component thereof) are no longer, or as of a specified future date will no longer be, representative.

For the avoidance of doubt, a "Benchmark Transition Event" will be deemed to have occurred with respect to any Benchmark if a public statement or publication of information set forth above has occurred with respect to each then-current Available Tenor of such Benchmark (or the published component used in the calculation thereof).

"Benchmark Unavailability Period" means, with respect to any Benchmark, the period (if any) (x) beginning at the time that a Benchmark Replacement Date pursuant to clauses (1) or (2) of that definition has occurred if, at such time, no Benchmark Replacement has replaced such then-current Benchmark for all purposes hereunder and under any Loan Document in accordance with Section 2.14 and (y) ending at the time that a Benchmark Replacement has replaced such then-current Benchmark for all purposes hereunder and under any Loan Document in accordance with Section 2.14.

"Beneficial Ownership Certification" means a certification regarding beneficial ownership or control as required by the Beneficial Ownership Regulation.

"Beneficial Ownership Regulation" means 31 C.F.R. § 1010.230.

"Benefit Plan" means any of (a) an "employee benefit plan" (as defined in Section 3(3) of ERISA) that is subject to Title I of ERISA, (b) a "plan" as defined in Section 4975 of the Code to which

Section 4975 of the Code applies, and (c) any Person whose assets include (for purposes of the Plan Asset Regulations or otherwise for purposes of Title I of ERISA or Section 4975 of the Code) the assets of any such "employee benefit plan" or "plan".

"Borrower" means Northwest Natural Holding Company, an Oregon corporation.

"Borrower Materials" has the meaning assigned to such term in Section 5.02.

"Borrowing" means Revolving Loans of the same Type, made, converted or continued on the same date and, in the case of Term Benchmark Loans, as to which a single Interest Period is in effect.

"Borrowing Request" means a request by the Borrower for a Revolving Borrowing in accordance with Section 2.03, which shall be substantially in the form attached hereto as Exhibit F-1 or any other form approved by the Administrative Agent.

"Business Day" means, any day (other than a Saturday or a Sunday) on which banks are open for business in New York City; provided that, in addition to the foregoing, a Business Day shall be a day that is also a U.S. Government Securities Business Day (a) in relation to RFR Loans and any interest rate settings, fundings, disbursements, settlements or payments of any such RFR Loan, or any other dealings of such RFR Loan and (b) in relation to Loans referencing the Adjusted Term SOFR Rate and any interest rate settings, fundings, disbursements, settlements or payments of any such Loans referencing the Adjusted Term SOFR Rate or any other dealings of such Loans referencing the Adjusted Term SOFR Rate.

"Carbon Savings KPI" means aggregate metric tons of greenhouse gasses saved since 2015 by NW Natural, as determined and calculated by NW Natural using the Carbon Savings KPI Calculation Methodology.

"Carbon Savings KPI Calculation Methodology" means the calculation methodology used by NW Natural to report carbon savings of 379,064 metric tons in the Borrower's 2020 Environmental, Social and Governance Report (a copy of which report has been delivered to the Administrative Agent, the Sustainability Structuring Agent and the Lenders prior to the Restatement Effective Date or otherwise published on an Internet or intranet website to which each Lender, the Sustainability Structuring Agent and the Administrative Agent have been granted access free of charge (or at the expense of the Borrower)), and as identified in the Baseline column of the Sustainability Table.

"Carbon Savings KPI Applicable Rate Adjustment Amount" means, with respect to any period between Sustainability Pricing Adjustment Dates, (a) positive 0.020%, if the Carbon Savings KPI for such period as set forth in the KPI Metrics Report is less than the Carbon Savings KPI Threshold A for such period, (b) 0.000%, if the Carbon Savings KPI for such period as set forth in the KPI Metrics Report is more than or equal to the Carbon Savings KPI Threshold A for such period but less than the Carbon Savings KPI Target A for such period, and (c) negative 0.020%, if the Carbon Savings KPI for such period as set forth in the KPI Metrics Report is more than or equal to Carbon Savings KPI Target A for such period.

"Carbon Savings KPI Facility Fee Adjustment Amount" means, with respect to any period between Sustainability Pricing Adjustment Dates, (a) positive 0.005%, if the Carbon Savings KPI for such period as set forth in the KPI Metrics Report is less than the Carbon Savings KPI Threshold A for such period, (b) 0.000%, if the Carbon Savings KPI for such period as set forth in the KPI Metrics Report is more than or equal to the Carbon Savings KPI Threshold A for such period but less than the Carbon Savings KPI Target A for such period, and (c) negative 0.005%, if the Carbon Savings KPI for such period as set forth in the KPI Metrics Report is more than or equal to Carbon Savings KPI Target A for such period.

"Carbon Savings KPI Target A" means, with respect to any Reference Year, the Carbon Savings KPI Target A for such Reference Year as set forth in the Sustainability Table.

"Carbon Savings KPI Threshold A" means, with respect to any Reference Year, the Carbon Savings KPI Threshold A for such Reference Year as set forth in the Sustainability Table.

"Change in Control" means that (a)(i) either (x) a person or group (as defined in the Securities Exchange Act of 1934) has acquired more than 50% of the voting stock of the Borrower or (y) a majority of the board of directors of the Borrower shall cease to be composed of individuals who were members of such board on the Restatement Effective Date ("Existing Directors") or were approved by a majority of the Existing Directors and previously approved directors; and (ii) at the time of, or at any time during the one-year period following, an event described in the preceding clause (a)(i), the Borrower either (x) has a rating that is not an Investment Grade Rating from any one of S&P, Fitch or Moody's or (y) does not have a credit rating from at least one of S&P, Fitch or Moody's.

"Change in Law" means the occurrence, after the date of this Agreement (or, with respect to any Lender, such later date on which such Lender becomes a party to this Agreement), of: (a) the adoption or taking effect of any law, rule, regulation or treaty, (b) any change in any law, rule, regulation or treaty or in the administration, interpretation, implementation or application thereof by any Governmental Authority, or (c) compliance by any Lender or Issuing Bank (or, for purposes of Section 2.15(b), by any lending office of such Lender or by such Lender's or Issuing Bank's holding company, if any) with any request, rule, guideline, requirement or directive (whether or not having the force of law) of any Governmental Authority made or issued after the date of this Agreement; provided that, notwithstanding anything herein to the contrary, (x) the Dodd-Frank Wall Street Reform and Consumer Protection Act and all requests, rules, guidelines, requirements or directives thereunder, or issued in connection therewith or in the implementation thereof, and (y) all requests, rules, guidelines, requirements and directives promulgated by the Bank for International Settlements, the Basel Committee on Banking Supervision (or any successor or similar authority) or the United States or foreign regulatory authorities, in each case pursuant to Basel III, shall in each case be deemed to be a "Change in Law" regardless of the date enacted, adopted, issued or implemented.

"Charges" has the meaning assigned to it in Section 9.16.

"CME Term SOFR Administrator" means CME Group Benchmark Administration Limited as administrator of the forward-looking term Secured Overnight Financing Rate (SOFR) (or a successor administrator).

"Co-Syndication Agents" means each of Bank of America, N.A., U.S. Bank National Association and Wells Fargo Bank, National Association.

"Code" means the Internal Revenue Code of 1986, as amended.

"Commitment" means, with respect to each Lender, the commitment of such Lender to make Revolving Loans and to acquire participations in Letters of Credit hereunder, expressed as an amount representing the maximum aggregate amount of such Lender's Revolving Credit Exposure hereunder, as such commitment may be (a) reduced or terminated from time to time pursuant to Section 2.09, (b) increased from time to time pursuant to Section 2.20 and (c) reduced or increased from time to time pursuant to assignments by or to such Lender pursuant to Section 9.04. The initial amount of each Lender's Commitment is set forth on Schedule 2.01A, or in the Assignment and Assumption or other documentation or record (as such term is defined in Section 9-102(a)(70) of the New York Uniform Commercial Code) as provided in Section 9.04(b)(ii)(C), pursuant to which such Lender shall have assumed its Commitment, as applicable.

"Commitment Schedule" means Schedule 2.01A and Schedule 2.01B attached hereto, as the context may require.

"Communications" has the meaning assigned to such term in Section 8.03(c).

"Connection Income Taxes" means Other Connection Taxes that are imposed on or measured by net income (however denominated) or that are gross receipts or franchise Taxes or branch profits Taxes.

"Consolidated Indebtedness" means, at a particular date, all Indebtedness, calculated for the Borrower and its Subsidiaries on a consolidated basis.

"Control" means the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of a Person, whether through the ability to exercise voting power, by contract or otherwise. "Controlling" and "Controlled" have meanings correlative thereto.

"Corresponding Tenor" with respect to any Available Tenor means, as applicable, either a tenor (including overnight) or an interest payment period having approximately the same length (disregarding business day adjustment) as such Available Tenor.

"Credit Event" means a Borrowing, the issuance, amendment, renewal or extension of a Letter of Credit, an LC Disbursement or any of the foregoing.

"Credit Party" means the Administrative Agent, each Issuing Bank or any other Lender.

"Daily Simple SOFR" means, for any day (a "SOFR Rate Day"), a rate per annum equal to SOFR for the day (such day "SOFR Determination Date") that is five (5) U.S. Government Securities Business Days prior to (i) if such SOFR Rate Day is a U.S. Government Securities Business Day, such SOFR Rate Day or (ii) if such SOFR Rate Day is not a U.S. Government Securities Business Day, the U.S. Government Securities Business Day immediately preceding such SOFR Rate Day, in each case, as such SOFR is published by the SOFR Administrator on the SOFR Administrator's Website. Any change in Daily Simple SOFR due to a change in SOFR shall be effective from and including the effective date of such change in SOFR without notice to the Borrower.

"Debt Rating" means the rating assigned by S&P or Moody's, as applicable, to the Borrower's senior, unsecured, non-credit enhanced long-term debt; provided that, (a) if the Borrower's senior, unsecured, non-credit enhanced long-term debt is not rated by S&P, "Debt Rating" for S&P shall mean the (i) the corporate credit rating assigned by S&P to the Borrower; or (ii) if the rating described in clause (a)(i) shall not exist with respect to S&P, the rating for S&P that is one level below the rating assigned by S&P to senior, unsecured, non-credit enhanced long-term debt of NW Natural; or (iii) if the ratings described in clause (a)(i) and (a)(ii) shall not exist with respect to S&P, the rating that is two levels below the rating assigned by S&P to the senior, secured long-term debt of NW Natural; and (b) if the Borrower's senior, unsecured, non-credit enhanced long-term debt is not rated by Moody's, "Debt Rating" for Moody's shall mean (i) the corporate credit rating assigned by Moody's to the Borrower; or (ii) if the rating described in clause (b)(i) shall not exist with respect to Moody's, the rating for Moody's that is one level below the rating assigned by Moody's to senior, unsecured, non-credit enhanced long-term debt of NW Natural; or (iii) if the ratings described in clause (b)(i) and (b)(ii) shall not exist with respect to Moody's, the rating that is two levels below the rating assigned by Moody's to the senior, secured long-term debt of NW Natural.

"Default" means any event or condition which constitutes an Event of Default or which upon notice, lapse of time or both would, unless cured or waived, become an Event of Default.

"Defaulting Lender" means any Lender that (a) has failed, within two (2) Business Days of the date required to be funded or paid, to (i) fund any portion of its Loans, (ii) fund any portion of its participations in Letters of Credit or (iii) pay over to any Credit Party any other amount required to be paid by it hereunder, unless, in the case of clause (i) above, a condition precedent to funding has not been satisfied or is subject to a good faith dispute and such Lender notifies the Administrative Agent in writing that such Lender has not funded because, in such Lender's good faith determination, such condition precedent to funding (specifically identified and including the particular default, if any) has not been satisfied, (b) has notified the Borrower or any Credit Party in writing, or has made a public statement to the effect, that it does not intend or expect to comply with any of its funding obligations under this Agreement (unless such writing or public statement indicates that such position is based on such Lender's good faith determination that a condition precedent (specifically identified and including the particular default, if any) to funding a Loan under this Agreement cannot be satisfied) or generally under other agreements in which it commits to extend credit, (c) has failed, within three (3) Business Days after request by a Credit Party, acting in good faith, to provide a certification in writing from an authorized officer of such Lender that it will comply with its obligations (and is financially able to meet such obligations) to fund prospective Loans and participations in then outstanding Letters of Credit under this Agreement, provided that such Lender shall cease to be a Defaulting Lender pursuant to this clause (c) upon such Credit Party's receipt of such certification in form and substance satisfactory to it and the Administrative Agent, or (d) has become the subject of (A) a Bankruptcy Event or (B) a Bail-In Action.

"Dollars" or "$" refers to lawful money of the United States of America.

"EEA Financial Institution" means (a) any credit institution or investment firm established in any EEA Member Country which is subject to the supervision of an EEA Resolution Authority, (b) any entity established in an EEA Member Country which is a parent of an institution described in clause (a) of this definition, or (c) any financial institution established in an EEA Member Country which is a subsidiary of an institution described in clauses (a) or (b) of this definition and is subject to consolidated supervision with its parent.

"EEA Member Country" means any of the member states of the European Union, Iceland, Liechtenstein, and Norway.

"EEA Resolution Authority" means any public administrative authority or any Person entrusted with public administrative authority of any EEA Member Country (including any delegee) having responsibility for the resolution of any EEA Financial Institution.

"Electronic Signature" means an electronic sound, symbol, or process attached to, or associated with, a contract or other record and adopted by a Person with the intent to sign, authenticate or accept such contract or record.

"Environmental Laws" means all laws, rules, regulations, codes, ordinances, orders, decrees, judgments, injunctions, notices or binding agreements issued, promulgated or entered into by any Governmental Authority, relating in any way to (i) the environment, (ii) preservation or reclamation of natural resources, (iii) the management, release or threatened release of any Hazardous Material or (iv) health and safety matters.

"Environmental Liability" means any liability, contingent or otherwise (including any liability for damages, costs of environmental remediation, fines, penalties or indemnities), of the Borrower or any Subsidiary directly or indirectly resulting from or based upon (a) violation of any Environmental Law, (b) the generation, use, handling, transportation, storage, treatment or disposal of any Hazardous Materials, (c) exposure to any Hazardous Materials, (d) the release or threatened release of any Hazardous Materials into the environment or (e) any contract, agreement or other consensual arrangement pursuant to which liability is assumed or imposed with respect to any of the foregoing.

"Equity Interests" means shares of capital stock, partnership interests, membership interests in a limited liability company, beneficial interests in a trust or other equity ownership interests in a Person, and any warrants, options or other rights entitling the holder thereof to purchase or acquire any such equity interest, but excluding any debt securities convertible into any of the foregoing.

"ERISA" means the Employee Retirement Income Security Act of 1974, as amended from time to time, and the rules and regulations promulgated thereunder.

"ERISA Affiliate" means any trade or business (whether or not incorporated) that, together with the Borrower, is treated as a single employer under Section 414(b) or (c) of the Code or Section 4001(b)(1) of ERISA or, solely for purposes of Section 302 of ERISA and Section 412 of the Code, is treated as a single employer under Section 414 of the Code.

"ERISA Event" means (a) any Reportable Event; (b) the failure to satisfy the "minimum funding standard" (as defined in Section 412 of the Code or Section 302 of ERISA), whether or not waived; (c) the filing pursuant to Section 412(c) of the Code or Section 302(c) of ERISA of an application for a waiver of the minimum funding standard with respect to any Plan; (d) the incurrence by the Borrower or any of its ERISA Affiliates of any liability under Title IV of ERISA with respect to the termination of any Plan; (e) the receipt by the Borrower or any ERISA Affiliate from the PBGC or a plan administrator of any notice relating to an intention to terminate any Plan or Plans or to appoint a trustee to administer any Plan; (f) the incurrence by the Borrower or any of its ERISA Affiliates of any liability with respect to the withdrawal or partial withdrawal of the Borrower or any of its ERISA Affiliates from any Plan or Multiemployer Plan; or (g) the receipt by the Borrower or any ERISA Affiliate of any notice, or the receipt by any Multiemployer Plan from the Borrower or any ERISA Affiliate of any notice, concerning the imposition upon the Borrower or any of its ERISA Affiliates of Withdrawal Liability or a determination that a Multiemployer Plan is, or is expected to be, insolvent or in reorganization, within the meaning of Title IV of ERISA.

"EU Bail-In Legislation Schedule" means the EU Bail-In Legislation Schedule published by the Loan Market Association (or any successor Person), as in effect from time to time.

"Event of Default" has the meaning assigned to such term in Section 7.01.

"Excluded Taxes" means any of the following Taxes imposed on or with respect to a Recipient or required to be withheld or deducted from a payment to a Recipient, (a) Taxes imposed on or measured by net income (however denominated), gross receipts, franchise Taxes, and branch profits Taxes, in each case, (i) imposed as a result of such Recipient being organized under the laws of, or having its principal office or, in the case of any Lender, its applicable lending office located in, the jurisdiction imposing such Tax (or any political subdivision thereof) or (ii) that are Other Connection Taxes, (b) in the case of a Lender, U.S. Federal withholding Taxes imposed on amounts payable to or for the account of such Lender with respect to an applicable interest in a Loan, Letter of Credit or Commitment pursuant to a law in effect on the date on which (i) such Lender acquires such interest in the Loan, Letter of Credit or Commitment (other than pursuant to an assignment request by the Borrower under Section 2.19(b)) or (ii) such Lender changes its lending office, except in each case to the extent that, pursuant to Section 2.17, amounts with respect to such Taxes were payable either to such Lender's assignor immediately before such Lender acquired the applicable interest in a Loan, Letter of Credit or Commitment or to such Lender immediately before it changed its lending office, (c) Taxes attributable to such Recipient's failure to comply with Section 2.17(f) and (d) any withholding Taxes imposed under FATCA.

"Existing Credit Agreement" has the meaning assigned to it in the Recitals to this Agreement.

"Existing Maturity Date" has the meaning assigned to such term in Section 2.22(a).

"Extending Lender" has the meaning assigned to such term in Section 2.22(b)(ii).

"Extension Request" means a written request from the Borrower to the Administrative Agent requesting an extension of the Maturity Date pursuant to Section 2.22.

"FATCA" means Sections 1471 through 1474 of the Code, as of the date of this Agreement (or any amended or successor version that is substantively comparable and not materially more onerous to comply with), any current or future regulations or official interpretations thereof, any agreement entered into pursuant to Section 1471(b)(1) of the Code and any fiscal or regulatory legislation, rules or practices adopted pursuant to any intergovernmental agreement, treaty or convention among Governmental Authorities and implementing such Sections of the Code.

"Federal Funds Effective Rate" means, for any day, the rate calculated by the NYFRB based on such day's federal funds transactions by depositary institutions, as determined in such manner as shall be set forth on the NYFRB's Website from time to time, and published on the next succeeding Business Day by the NYFRB as the effective federal funds rate; provided that if the Federal Funds Effective Rate as so determined would be less than zero, such rate shall be deemed to be zero for the purposes of this Agreement.

"Federal Reserve Board" means the Board of Governors of the Federal Reserve System of the United States of America.

"Financial Officer" means the chief financial officer, principal accounting officer, treasurer or controller of the Borrower.

"Fitch" means Fitch, Inc., doing business as Fitch Ratings.

"Floor" means the benchmark rate floor, if any, provided in this Agreement initially (as of the execution of this Agreement, the modification, amendment or renewal of this Agreement or otherwise) with respect to the Adjusted Term SOFR Rate or the Adjusted Daily Simple SOFR, as applicable. For the avoidance of doubt, the initial Floor for each of Adjusted Term SOFR Rate or the Adjusted Daily Simple SOFR shall be 0%.

"Foreign Lender" means (a) if the Borrower is a U.S. Person, a Lender that is not a U.S. Person, and (b) if the Borrower is not a U.S. Person, a Lender that is resident or organized under the laws of a jurisdiction other than that in which the Borrower is resident for tax purposes.

"GAAP" means generally accepted accounting principles in the United States of America in effect from time to time.

"Governmental Authority" means the government of the United States of America, any other nation or any political subdivision thereof, whether state or local, and any agency, authority, instrumentality, regulatory body, court, central bank or other entity exercising executive, legislative, judicial, taxing, regulatory or administrative powers or functions of or pertaining to government.

"Hazardous Materials" means all explosive or radioactive substances or wastes and all hazardous or toxic substances, wastes or other pollutants, including petroleum or petroleum distillates, asbestos or asbestos containing materials, polychlorinated biphenyls, radon gas, infectious or medical wastes and all other substances or wastes of any nature regulated pursuant to any Environmental Law.

"Hostile Acquisition" means (a) the acquisition of the Equity Interests of a Person through a tender offer or similar solicitation of the owners of such Equity Interests which has not been approved (prior to such acquisition) by the board of directors (or any other applicable governing body) of such Person or by similar action if such Person is not a corporation and (b) any such acquisition as to which such approval has been withdrawn.

"Hybrid Securities" means debt or equity securities that meet the following requirements: (a) such securities are issued by (i) the Borrower or (ii) a Subsidiary or an independent trust (a "Hybrid Securities Subsidiary") that engages in no business other than the issuance of such securities and lending the proceeds thereof to the Borrower; (b) each of such securities of the Borrower and the loans, if any, made to the Borrower by the applicable Hybrid Securities Subsidiary with the proceeds of such securities (i) are subordinated to the payment by the Borrower of its obligations hereunder in a manner reasonably satisfactory to the Administrative Agent and (ii) require no repayment, prepayment, mandatory redemption or mandatory repurchase prior to the date that is at least 91 days after the scheduled Maturity Date; and (c) such securities are classified as possessing a minimum of at least one of the following: (x) "intermediate equity content" by S&P, (y) "Basket C equity credit" by Moody's and (z) "50% equity credit" by Fitch.

"Increasing Lender" has the meaning assigned to such term in Section 2.20.

"Incremental Term Loan" has the meaning assigned to such term in Section 2.20.

"Incremental Term Loan Amendment" has the meaning assigned to such term in Section 2.20.

"Indebtedness" of a Person means, at a particular date, the sum (without duplication) at such date of (a) indebtedness for borrowed money or for the deferred purchase price of property, goods or services, excluding (i) trade accounts payable arising in the ordinary course of business, (ii) pension liabilities that are not then due and payable and (iii) obligations in respect of Hybrid Securities that are not then due and payable, (b) obligations of such Person under capitalized leases and synthetic leases, (c) debts of third persons guaranteed by such Person or secured by property of such Person (provided that the amount of Indebtedness secured by property of such Person shall be the lesser of (x) the fair market value of such property as of the date of determination and (y) the amount of the Indebtedness as of the date of determination) and (d) any non-contingent reimbursement obligations of such Person in respect of letters of credit, acceptances or similar obligations issued or created for the account of such Person.

"Indemnified Taxes" means (a) Taxes, other than Excluded Taxes, imposed on or with respect to any payment made by or on account of any obligation of the Borrower under any Loan Document and (b) to the extent not otherwise described in clause (a) hereof, Other Taxes.

"Indemnitee" has the meaning assigned to it in Section 9.03(b).

"Ineligible Institution" has the meaning assigned to such term in Section 9.04(b).

"Information" has the meaning assigned to it in Section 9.12.

"Information Memorandum" means the Confidential Information Memorandum dated October 13, 2021 relating to the Borrower and the Transactions.

"Interest Election Request" means a request by the Borrower to convert or continue a Revolving Borrowing in accordance with Section 2.08, which shall be substantially in the form attached hereto as Exhibit F-2 or any other form approved by the Administrative Agent.

"Interest Payment Date" means (a) with respect to any ABR Loan, the second Business Day following the last day of each March, June, September and December and the Maturity Date, (b) with respect to any Term Benchmark Loan, the last day of each Interest Period applicable to the Borrowing of which such Loan is a part and, in the case of a Term Benchmark Borrowing with an Interest Period of more than three months' duration, each day prior to the last day of such Interest Period that occurs at intervals of three months' duration after the first day of such Interest Period, and the Maturity Date and (c) with respect to any RFR Loan, (1) each date that is on the numerically corresponding day in each calendar month that is one month after the Borrowing of such Loan (or, if there is no such numerically corresponding day in such month, then the last day of such month) and (2) the Maturity Date.

"Interest Period" means, with respect to any Term Benchmark Borrowing, the period commencing on the date of such Borrowing and ending on the numerically corresponding day in the calendar month that is one, three or six months thereafter (in each case, subject to the availability for the Benchmark applicable to the relevant Loan or Commitment), as the Borrower may elect; provided, that (i) if any Interest Period would end on a day other than a Business Day, such Interest Period shall be extended to the next succeeding Business Day unless such next succeeding Business Day would fall in the next calendar month, in which case such Interest Period shall end on the next preceding Business Day, (ii) any Interest Period that commences on the last Business Day of a calendar month (or on a day for which there is no numerically corresponding day in the last calendar month of such Interest Period) shall end on the last Business Day of the last calendar month of such Interest Period, and (iii) no tenor that has been removed from this definition pursuant to Section 2.14(e) shall be available for specification in such Borrowing Request or Interest Election Request. For purposes hereof, the date of a Borrowing initially shall be the date on which such Borrowing is made and, in the case of a Revolving Borrowing, thereafter shall be the effective date of the most recent conversion or continuation of such Borrowing.

"Investment Grade Rating" means, for S&P, Fitch or Moody's, as applicable, (a) if such rating agency has a rating assigned to the Borrower's senior, unsecured, non-credit enhanced long-term debt of BBB- or higher by S&P or Fitch and Baa3 or higher by Moody's; and (b) if such rating agency does not have a rating assigned to the Borrower's senior, unsecured, non-credit enhanced long-term debt but has a rating assigned to the Borrower's senior, secured long-term debt, BBB or higher by S&P or Fitch and Baa2 or higher by Moody's.

"IRS" means the United States Internal Revenue Service.

"Issuing Bank" means JPMorgan Chase Bank, N.A., Bank of America, N.A., U.S. Bank National Association and Wells Fargo Bank, National Association and any other Lender that agrees to act as an Issuing Bank (in each case, through itself or through one of its designated Affiliates or branch offices), each in its capacity as the issuer of Letters of Credit hereunder, and its successors in such capacity as provided in Section 2.06(i). Any Issuing Bank may, in its discretion, arrange for one or more Letters of Credit to be issued by Affiliates of such Issuing Bank, in which case the term "Issuing Bank" shall include any such Affiliate with respect to Letters of Credit issued by such Affiliate. Each reference herein to the "Issuing Bank" in connection with a Letter of Credit or other matter shall be deemed to be a reference to the relevant Issuing Bank with respect thereto.

"KPI Metric" means each of the Carbon Savings KPI and the Transmission Pipeline Inspection KPI.

"KPI Metric Calculation Methodology" means the Carbon Savings KPI Metric Calculation Methodology and the Transmission Pipeline Inspection KPI Calculation Methodology.

"KPI Metrics Report" means an annual report (it being understood that this annual report may take the form of the annual Sustainability Report) that sets forth the calculations for each KPI Metric for a specific Reference Year. The Sustainability Assurance Provider shall attest to the KPI Metrics for verification of the method of calculation of each KPI Metric in conformity with the applicable KPI Metric Calculation Methodology.

"LC Collateral Account" has the meaning assigned to such term in Section 2.06(j).

"LC Disbursement" means a payment made by an Issuing Bank pursuant to a Letter of Credit.

"LC Exposure" means, at any time, the sum of (a) the aggregate undrawn amount of all outstanding Letters of Credit at such time plus (b) the aggregate amount of all LC Disbursements that have not yet been reimbursed by or on behalf of the Borrower at such time. The LC Exposure of any Lender at any time shall be its Applicable Percentage of the total LC Exposure at such time. For all purposes of this Agreement, if on any date of determination a Letter of Credit has expired by its terms but any amount may still be drawn thereunder by reason of the operation of Article 29(a) of the Uniform Customs and Practice for Documentary Credits, International Chamber of Commerce Publication No. 600 (or such later version thereof as may be in effect at the applicable time) or Rule 3.13 or Rule 3.14 of the International Standby Practices, International Chamber of Commerce Publication No. 590 (or such later version thereof as may be in effect at the applicable time) or similar terms of the Letter of Credit itself, or if compliant documents have been presented but not yet honored, such Letter of Credit shall be deemed to be "outstanding" and "undrawn" in the amount so remaining available to be paid, and the obligations of the Borrower and each Lender shall remain in full force and effect until the Issuing Banks and the Lenders shall have no further obligations to make any payments or disbursements under any circumstances with respect to any Letter of Credit.

"Lender Parent" means, with respect to any Lender, any Person as to which such Lender is, directly or indirectly, a subsidiary.

"Lender-Related Person" has the meaning assigned to it in Section 9.03(d).

"Lenders" means the Persons listed on Schedule 2.01A and any other Person that shall have become a party hereto pursuant to an Assignment and Assumption or otherwise, other than any such Person that ceases to be a party hereto pursuant to an Assignment and Assumption or otherwise. Unless the context otherwise requires, the term "Lenders" includes the Issuing Banks.

"Letter of Credit" means any letter of credit issued pursuant to this Agreement.

"Letter of Credit Agreement" has the meaning assigned to it in Section 2.06(b).

"Letter of Credit Commitment" means, with respect to each Issuing Bank, the commitment of such Issuing Bank to issue Letters of Credit hereunder. The initial amount of each Issuing Bank's Letter of Credit Commitment is set forth on Schedule 2.01B, or if an Issuing Bank has entered into an Assignment and Assumption or has otherwise assumed a Letter of Credit Commitment after the Restatement Effective Date, the amount set forth for such Issuing Bank as its Letter of Credit Commitment in the Register maintained by the Administrative Agent. The Letter of Credit Commitment of an Issuing Bank may be modified from time to time by agreement between such Issuing Bank and the Borrower, and notified to the Administrative Agent.

"Liabilities" means any losses, claims (including intraparty claims), demands, damages or liabilities of any kind.

"Loan Documents" means this Agreement, including schedules and exhibits hereto, and any agreements entered into in connection herewith by the Borrower with or in favor of the Administrative Agent and/or the Lenders, including any promissory notes issued pursuant to Section 2.10(e), any amendments, modifications or supplements thereto or waivers thereof, UCC filings, letter of credit applications and any agreements between the Borrower and an Issuing Bank regarding the issuance by such Issuing Bank of Letters of Credit hereunder and/or the respective rights and obligations between the Borrower and such Issuing Bank in connection thereunder and any other documents instruments or certificates delivered by the Borrower pursuant to the terms of any other Loan Document. Any reference in this Agreement or any other Loan Document to a Loan Document shall include all appendices, exhibits or schedules thereto, and all amendments, restatements, supplements or other modifications thereto, and shall refer to this Agreement or such Loan Document as the same may be in effect at any and all times such reference becomes operative.

"Loans" means the loans made by the Lenders to the Borrower pursuant to this Agreement.

"Margin Stock" means margin stock within the meaning of Regulations T, U and X, as applicable.

"Material Adverse Effect" means a material adverse effect on (a) the operations, the business or financial condition of the Borrower and its Subsidiaries taken as a whole, (b) the ability of the Borrower to perform any of its Obligations or (c) the validity or enforceability of this Agreement or any and all other Loan Documents or the rights or remedies of the Administrative Agent and the Lenders thereunder.

"Maturity Date" means, with respect to any Lender, the later of (a) November 3, 2026 and (b) if the maturity date is extended for such Lender pursuant to Section 2.22, such extended maturity date as determined pursuant to such Section; *provided*, *however*, in each case, if such date is not a Business Day, the Maturity Date shall be the next preceding Business Day.

"Maximum Rate" has the meaning assigned to it in Section 9.16.

"Moody's" means Moody's Investors Service, Inc.

"Multiemployer Plan" means a multiemployer plan as defined in Section 4001(a)(3) of ERISA.

"Non-extending Lender" has the meaning assigned to such term in Section 2.22(a).

"NW Natural" means Northwest Natural Gas Company, an Oregon corporation.

"NYFRB" means the Federal Reserve Bank of New York.

"NYFRB's Website" means the website of the NYFRB at http://www.newyorkfed.org or any successor source.

"NYFRB Rate" means, for any day, the greater of (a) the Federal Funds Effective Rate in effect on such day and (b) the Overnight Bank Funding Rate in effect on such day (or for any day that is not a Business Day, for the immediately preceding Business Day); provided that if none of such rates are published for any day that is a Business Day, the term "NYFRB Rate" means the rate for a federal funds transaction quoted at 11:00 a.m. on such day received by the Administrative Agent from a federal funds broker of recognized standing selected by it; provided, further, that if any of the aforesaid rates as so determined would be less than zero, such rate shall be deemed to be zero for purposes of this Agreement.

"Obligations" means all advances to, and debts, liabilities, obligations, covenants and duties of, the Borrower and its Subsidiaries arising under any Loan Document or otherwise with respect to any Loan or Letter of Credit, whether direct or indirect (including those acquired by assumption), absolute or contingent, due or to become due, now existing or hereafter arising and including interest and fees that accrue after the commencement by or against the Borrower or any Affiliate thereof of any proceeding under any debtor relief laws naming such Person as the debtor in such proceeding, regardless of whether such interest and fees are allowed or allowable claims in such proceeding. Without limiting the foregoing, the Obligations include (a) the obligation to pay principal, interest, Letter of Credit commissions, charges, expenses, fees, indemnities and other amounts payable by the Borrower under any Loan Document and (b) the obligation of the Borrower to reimburse any amount in respect of any of the foregoing that the Administrative Agent or any Lender, in each case in its sole discretion, may elect to pay or advance on behalf of the Borrower.

"OFAC" means the Office of Foreign Assets Control of the U.S. Department of the Treasury.

"Other Connection Taxes" means, with respect to any Recipient, Taxes imposed as a result of a present or former connection between such Recipient and the jurisdiction imposing such Tax (other than connections arising from such Recipient having executed, delivered, become a party to, performed its obligations under, received payments under, received or perfected a security interest under, engaged in any other transaction pursuant to or enforced any Loan Document, or sold or assigned an interest in any Loan, Letter of Credit or Loan Document).

"Other Taxes" means all present or future stamp, court or documentary, intangible, recording, filing or similar Taxes that arise from any payment made under, from the execution, delivery, performance, enforcement or registration of, from the receipt or perfection of a security interest under, or otherwise with respect to, any Loan Document, except any such Taxes that are Other Connection Taxes imposed with respect to an assignment (other than an assignment made pursuant to Section 2.19).

"Overnight Bank Funding Rate" means, for any day, the rate comprised of both overnight federal funds and overnight eurodollar transactions denominated in Dollars by U.S.-managed banking offices of depository institutions, as such composite rate shall be determined by the NYFRB as set forth on the NYFRB's Website from time to time, and published on the next succeeding Business Day by the NYFRB as an overnight bank funding rate.

"Participant" has the meaning assigned to such term in Section 9.04(c).

"Participant Register" has the meaning assigned to such term in Section 9.04(c).

"Patriot Act" has the meaning assigned to such term in Section 9.14.

"Payment" has the meaning assigned to such term in Section 8.06(c).

"Payment Notice" has the meaning assigned to such term in Section 8.06(c).

"PBGC" means the Pension Benefit Guaranty Corporation referred to and defined in ERISA and any successor entity performing similar functions.

"Person" means any natural person, corporation, limited liability company, trust, joint venture, association, company, partnership, Governmental Authority or other entity.

"Plan" means any employee pension benefit plan (other than a Multiemployer Plan) subject to the provisions of Title IV of ERISA or Section 412 of the Code or Section 302 of ERISA, and in respect of which the Borrower or any ERISA Affiliate is (or, if such plan were terminated, would under Section 4069 of ERISA be deemed to be) an "employer" as defined in Section 3(5) of ERISA.

"Plan Asset Regulations" means 29 CFR § 2510.3-101 et seq., as modified by Section 3(42) of ERISA.

"Platform" has the meaning assigned to such term in Section 5.02.

"Pricing Certificate" means a certificate executed by the chief executive officer, chief financial officer, treasurer, controller or any vice president of the Borrower and attaching (a) true and correct copies of the KPI Metrics Report for the most recently ended Reference Year and setting forth the Sustainability Rate Adjustment and the Sustainability Facility Fee Adjustment for the period covered thereby and computations in reasonable detail in respect thereof and (b) a review report of the Sustainability Assurance Provider confirming that the Sustainability Assurance Provider is not aware of any modifications that should be made to such computations in order for them to be presented in all material respects in conformity with the KPI Metric Calculation Methodology.

"Pricing Certificate Inaccuracy" has the meaning assigned to such term in Section 1.08(d).

"Prime Rate" means the rate of interest last quoted by The Wall Street Journal as the "Prime Rate" in the U.S. or, if The Wall Street Journal ceases to quote such rate, the highest per annum interest rate published by the Federal Reserve Board in Federal Reserve Statistical Release H.15 (519) (Selected Interest Rates) as the "bank prime loan" rate or, if such rate is no longer quoted therein, any similar rate quoted therein (as determined by the Administrative Agent) or any similar release by the Federal Reserve Board (as determined by the Administrative Agent). Each change in the Prime Rate shall be effective from and including the date such change is publicly announced or quoted as being effective.

"Proceeding" means any claim, litigation, investigation, action, suit, arbitration or administrative, judicial or regulatory action or proceeding in any jurisdiction.

"PTE" means a prohibited transaction class exemption issued by the U.S. Department of Labor, as any such exemption may be amended from time to time.

"Public Lender" has the meaning assigned to such term in Section 5.02.

"Recipient" means (a) the Administrative Agent, (b) any Lender and (c) any Issuing Bank, as applicable.

"Reference Time" with respect to any setting of the then-current Benchmark means (1) if such Benchmark is the Term SOFR Rate, 5:00 a.m. (Chicago time) on the day that is two (2) U.S. Government Securities Business Days preceding the date of such setting, (2) if, following a Benchmark Transition Event and Benchmark Replacement Date with respect to the Term SOFR Rate, such Benchmark is Daily Simple SOFR, then four (4) Business Days prior to such setting and (3) if such Benchmark is not the Term SOFR Rate or Daily Simple SOFR, the time determined by the Administrative Agent in its reasonable discretion.

"Reference Year" means, with respect to any Pricing Certificate, the fiscal year ending immediately prior to the date of such Pricing Certificate.

"Register" has the meaning assigned to such term in Section 9.04(b).

"Regulation D" means Regulation D of the Federal Reserve Board, as in effect from time to time and all official rulings and interpretations thereunder or thereof.

"Regulation T" means Regulation T of the Federal Reserve Board, as in effect from time to time and all official rulings and interpretations thereunder or thereof.

"Regulation U" means Regulation U of the Federal Reserve Board, as in effect from time to time and all official rulings and interpretations thereunder or thereof.

"Regulation X" means Regulation X of the Federal Reserve Board, as in effect from time to time and all official rulings and interpretations thereunder or thereof.

"Related Parties" means, with respect to any specified Person, such Person's Affiliates and the respective directors, officers, employees, agents, advisors and representatives of such Person and such Person's Affiliates.

"Relevant Governmental Body" means the Federal Reserve Board and/or the NYFRB, or a committee officially endorsed or convened by the Federal Reserve Board or the NYFRB, or, in each case, any successor thereto.

"Relevant Rate" means (i) with respect to any Term Benchmark Borrowing, the Adjusted Term SOFR Rate or (ii) with respect to any RFR Borrowing following a Benchmark Transition Event and Benchmark Replacement Date with respect to the Term SOFR Rate, Adjusted Daily Simple SOFR, as applicable.

"Reportable Event" means a reportable event, as defined in Section 4043 of ERISA and the regulations issued under such section, with respect to a Plan, excluding any event as to which the PBGC by regulation waived the requirements of Section 4043(a) of ERISA that it be notified within 30 days of the occurrence of such event, provided that a failure to meet the minimum funding standard of Section 412 of the Code and of Section 302 of ERISA shall be a Reportable Event regardless of the issuance of any such waiver of the notice requirement in accordance with either Section 4043(a) of ERISA or Section 412(c) of the Code.

"Replacement Lender" has the meaning assigned to such term in Section 2.22(c).

"Required Lenders" means, subject to Section 2.21, at any time, Lenders having Revolving Credit Exposures and unused Commitments representing more than 50% of the sum of the Total Revolving Credit Exposure and unused Commitments at such time.

"Requirement of Law" means, as to any Person, the certificate of incorporation and bylaws or other organizational or governing documents of such Person, and any law, treaty, rule or regulation or order or determination of an arbitrator or a court or other Governmental Authority, in each case applicable to or binding upon such Person or any of its property or to which such Person or any of its property is subject.

"Resolution Authority" means an EEA Resolution Authority or, with respect to any UK Financial Institution, a UK Resolution Authority.

"Response Date" has the meaning assigned to such term in Section 2.22(a).

"Responsible Officer" means the chief executive officer, the president, any senior vice president, the chief financial officer, the chief accounting officer, the treasurer or the general counsel of the Borrower.

"Restatement Effective Date" means the date on which the conditions specified in Section 4.01 are satisfied (or waived in accordance with Section 9.02).

"Revolving Credit Exposure" means, with respect to any Lender at any time, the sum of the outstanding principal amount of such Lender's Revolving Loans and its LC Exposure at such time.

"Revolving Loan" means a Loan made pursuant to Section 2.03.

"RFR Borrowing" means, as to any Borrowing, the RFR Loans comprising such Borrowing.

"RFR Loan" means a Loan that bears interest at a rate based on the Adjusted Daily Simple SOFR.

"S&P" means Standard & Poor's Ratings Services, a Standard & Poor's Financial Services LLC business.

"Sanctioned Country" means, at any time, a country, region or territory (other than the United States or any region or territory therein) which is itself the subject or target of any Sanctions (at the time of this Agreement, the so-called Donetsk People's Republic, the so-called Luhansk People's Republic, the Crimea Region of Ukraine, Cuba, Iran, North Korea and Syria).

"Sanctioned Person" means, at any time, (a) any Person listed in any Sanctions-related list of designated Persons maintained by OFAC, the U.S. Department of State, the United Nations Security Council, the European Union, any European Union member state, His Majesty's Treasury of the United Kingdom, or other relevant sanctions authority, (b) any Person operating, organized or resident in a Sanctioned Country, (c) any Person owned or controlled by any such Person or Persons described in the foregoing clauses (a) or (b), or (d) any Person otherwise the subject of any Sanctions.

"Sanctions" means all economic or financial sanctions or trade embargoes imposed, administered or enforced from time to time by (a) the U.S. government, including those administered by OFAC or the U.S. Department of State, or (b) the United Nations Security Council, the European Union, any European Union member state, His Majesty's Treasury of the United Kingdom or other relevant sanctions authority.

"SEC" means the Securities and Exchange Commission of the United States of America.

"Securities Act" means the United States Securities Act of 1933.

"Significant Subsidiary" means a Subsidiary that is a "significant subsidiary" as that term is defined in Rule 1-02(w) of Regulation S-X promulgated by the SEC (as in effect on the Restatement Effective Date).

"SOFR" means, a rate equal to the secured overnight financing rate as administered by the SOFR Administrator.

"SOFR Administrator" means the NYFRB (or a successor administrator of the secured overnight financing rate).

"SOFR Administrator's Website" means the NYFRB's Website, currently at http://www.newyorkfed.org, or any successor source for the secured overnight financing rate identified as such by the SOFR Administrator from time to time.

"SOFR Determination Date" has the meaning specified in the definition of "Daily Simple SOFR".

"SOFR Rate Day" has the meaning specified in the definition of "Daily Simple SOFR".

"subsidiary" means, with respect to any Person (the "parent") at any date, any corporation, limited liability company, partnership, association or other entity (a) of which securities or other ownership interests representing more than 50% of the equity or more than 50% of the ordinary voting power or, in the case of a partnership, more than 50% of the general partnership interests are, as of such date, owned, Controlled or held, or (b) that is, as of such date, otherwise Controlled, by the parent and/or one or more subsidiaries of the parent.

"Subsidiary" means any subsidiary of the Borrower.

"Sustainability Assurance Provider" means PricewaterhouseCoopers LLP, or any replacement sustainability assurance provider thereof as designated from time to time by the Borrower; provided, that, any such replacement Sustainability Assurance Provider (a) shall be (i) a qualified external reviewer, independent of the Borrower and its Subsidiaries, with relevant expertise, such as an auditor, environmental consultant and/or independent ratings agency of recognized national standing or (ii) another firm designated by the Borrower and approved by the Required Lenders, and (b) shall apply substantially the same attestation standards and methodology used in the KPI Metric Calculation Methodologies, except for any changes to such standards and/or methodology that are approved by the Borrower and either (x) are consistent with then generally accepted industry standards or (y) if not so consistent, are approved by the Required Lenders.

"Sustainability Facility Fee Adjustment" means, with respect to any KPI Metrics Report for any period between Sustainability Pricing Adjustment Dates, an amount (whether positive, negative or zero), expressed as a percentage, equal to the sum of (a) the Carbon Savings KPI Facility Fee Adjustment Amount (whether positive, negative or zero), plus (b) the Transmission Pipeline Inspection KPI Facility Fee Adjustment Amount (whether positive, negative or zero), in each case for such period.

"Sustainability Pricing Adjustment Date" has the meaning specified in Section 1.08(a).

"Sustainability Rate Adjustment" with respect to any KPI Metrics Report for any period between Sustainability Pricing Adjustment Dates, an amount (whether positive, negative or zero), expressed as a percentage, equal to the sum of (a) the Carbon Savings KPI Applicable Rate Adjustment Amount (whether positive, negative or zero), plus (b) the Transmission Pipeline Inspection KPI Applicable Rate Adjustment Amount (whether positive, negative or zero), in each case for such period.

"Sustainability Report" means the annual non-financial disclosure report reported by the Borrower (it being understood that this report may take the form of the Borrower's annual Environmental, Social and Governance Report, a separate sustainability report or a separate report regarding only the KPI Metrics) and published on an Internet or intranet website to which each Lender and the Administrative Agent have been granted access free of charge (or at the expense of the Borrower).

"Sustainability Structuring Agent" means J.P. Morgan Securities LLC, in its capacity as sustainability structuring agent hereunder.

"Sustainability Table" means the Sustainability Table set forth on Schedule 1.08 hereto.

"Swap Agreement" means any agreement with respect to any swap, forward, future or derivative transaction or option or similar agreement involving, or settled by reference to, one or more rates, currencies, commodities, equity or debt instruments or securities, or economic, financial or pricing indices or measures of economic, financial or pricing risk or value or any similar transaction or any combination of these transactions; provided that no phantom stock or similar plan providing for payments only on account of services provided by current or former directors, officers, employees or consultants of the Borrower or the Subsidiaries shall be a Swap Agreement.

"Taxes" means all present or future taxes, levies, imposts, duties, deductions, withholdings (including backup withholding), value added taxes, or any other goods and services, use or sales taxes, assessments, fees or other charges imposed by any Governmental Authority, including any interest, additions to tax or penalties applicable thereto.

"Term Benchmark" when used in reference to any Loan or Borrowing, refers to whether such Loan, or the Loans comprising such Borrowing, are bearing interest at a rate determined by reference to the Adjusted Term SOFR Rate.

"Term SOFR Determination Day" has the meaning assigned to it under the definition of Term SOFR Reference Rate.

"Term SOFR Rate" means, with respect to any Term Benchmark Borrowing and for any tenor comparable to the applicable Interest Period, the Term SOFR Reference Rate at approximately 5:00 a.m., Chicago time, two U.S. Government Securities Business Days prior to the commencement of such tenor comparable to the applicable Interest Period, as such rate is published by the CME Term SOFR Administrator.

"Term SOFR Reference Rate" means, for any day and time (such day, the "Term SOFR Determination Day"), with respect to any Term Benchmark Borrowing and for any tenor comparable to the applicable Interest Period, the rate per annum published by the CME Term SOFR Administrator and identified by the Administrative Agent as the forward-looking term rate based on SOFR. If by 5:00 pm (New York City time) on such Term SOFR Determination Day, the "Term SOFR Reference Rate" for the applicable tenor has not been published by the CME Term SOFR Administrator and a Benchmark Replacement Date with respect to the Term SOFR Rate has not occurred, then so long as such day is otherwise a U.S. Government Securities Business Day, the Term SOFR Reference Rate for such Term SOFR Determination Day will be the Term SOFR Reference Rate as published in respect of the first preceding U.S. Government Securities Business Day for which such Term SOFR Reference Rate was published by the CME Term SOFR Administrator, so long as such first preceding U.S. Government Securities Business Day is not more than five (5) U.S. Government Securities Business Days prior to such Term SOFR Determination Day.

"Total Capitalization" means the sum of Indebtedness, Equity Interests, additional paid-in capital and retained earnings of the Borrower and its Subsidiaries, taken on a consolidated basis after eliminating all intercompany items.

"Total Revolving Credit Exposure" means the sum of the outstanding principal amount of all Lenders' Revolving Loans and their LC Exposure at such time.

"Transactions" means the execution and delivery by the Borrower of, and the performance by the Borrower of its obligations under, this Agreement and the other Loan Documents, the borrowing of Loans and other credit extensions, the use of the proceeds thereof and the issuance of Letters of Credit hereunder.

"Transmission Pipeline Inspection KPI" means miles of NW Natural's transmission pipeline that are inspected using the in-line inspection approach, as determined and calculated by NW Natural using the Transmission Pipeline Inspection KPI Calculation Methodology.

"Transmission Pipeline Inspection KPI Calculation Methodology" means the calculation methodology used by NW Natural to report 42 miles of transmission pipeline inspected in NW Natural's U.S. DOT PHMSA Annual Report for the calendar year 2020, a copy of which report has been delivered to the Administrative Agent, the Sustainability Structuring Agent and the Lenders prior to the Closing Date, and as identified in the Baseline column of the Sustainability Table.

"Transmission Pipeline Inspection KPI Applicable Rate Adjustment Amount" means, with respect to any period between Sustainability Pricing Adjustment Dates, (a) positive 0.020%, if the Transmission Pipeline Inspection KPI for such period as set forth in the KPI Metrics Report is less than the Transmission Pipeline Inspection KPI Threshold B for such period, (b) 0.000%, if the Transmission Pipeline Inspection KPI for such period as set forth in the KPI Metrics Report is more than or equal to the Transmission Pipeline Inspection KPI Threshold B for such period but less than the Transmission Pipeline Inspection KPI Target B for such period, and (c) negative 0.020%, if the Transmission Pipeline Inspection KPI for such period as set forth in the KPI Metrics Report is more than or equal to Transmission Pipeline Inspection KPI Target B for such period.

"Transmission Pipeline Inspection KPI Facility Fee Adjustment Amount" means, with respect to any period between Sustainability Pricing Adjustment Dates, (a) positive 0.005%, if the Transmission Pipeline Inspection KPI for such period as set forth in the KPI Metrics Report is less than the Transmission Pipeline Inspection KPI Threshold B for such period, (b) 0.000%, if the Transmission Pipeline Inspection KPI for such period as set forth in the KPI Metrics Report is more than or equal to the Transmission Pipeline Inspection KPI Threshold B for such period but less than the Transmission Pipeline Inspection KPI Target B for such period, and (c) negative 0.005%, if the Transmission Pipeline Inspection KPI for such period as set forth in the KPI Metrics Report is more than or equal to Transmission Pipeline Inspection KPI Target B for such period.

"Transmission Pipeline Inspection KPI Target B" means, with respect to any calendar year, the Transmission Pipeline Inspection KPI Target B for such calendar year as set forth in the Sustainability Table.

"Transmission Pipeline Inspection KPI Threshold B" means, with respect to any Reference Year, the Transmission Pipeline Inspection KPI Threshold B for such Reference Year as set forth in the Sustainability Table.

"Type", when used in reference to any Loan or Borrowing, refers to whether the rate of interest on such Loan, or on the Loans comprising such Borrowing, is determined by reference to the Adjusted Term SOFR Rate, Adjusted Daily Simple SOFR or the Alternate Base Rate.

"UK Financial Institutions" means any BRRD Undertaking (as such term is defined under the PRA Rulebook (as amended from time to time) promulgated by the United Kingdom Prudential Regulation Authority) or any person falling within IFPRU 11.6 of the FCA Handbook (as amended from time to time) promulgated by the United Kingdom Financial Conduct Authority, which includes certain credit institutions and investment firms, and certain affiliates of such credit institutions or investment firms.

"UK Resolution Authority" means the Bank of England or any other public administrative authority having responsibility for the resolution of any UK Financial Institution.

"Unadjusted Benchmark Replacement" means the applicable Benchmark Replacement excluding the related Benchmark Replacement Adjustment.

"U.S. Government Securities Business Day" means, any day except for (i) a Saturday, (ii) a Sunday or (iii) a day on which the Securities Industry and Financial Markets Association recommends that the fixed income departments of its members be closed for the entire day for purposes of trading in United States government securities.

"U.S. Person" means a "United States person" within the meaning of Section 7701(a)(30) of the Code.

"U.S. Tax Compliance Certificate" has the meaning assigned to such term in Section 2.17(f)(ii)(B)(3).

"Withdrawal Liability" means liability to a Multiemployer Plan as a result of a complete or partial withdrawal from such Multiemployer Plan, as such terms are defined in Part 1 of Subtitle E of Title IV of ERISA.

"Write-Down and Conversion Powers" means, (a) with respect to any EEA Resolution Authority, the write-down and conversion powers of such EEA Resolution Authority from time to time under the Bail-In Legislation for the applicable EEA Member Country, which write-down and conversion powers are described in the EU Bail-In Legislation Schedule, and (b) with respect to the United Kingdom, any powers of the applicable Resolution Authority under the Bail-In Legislation to cancel, reduce, modify or change the form of a liability of any UK Financial Institution or any contract or instrument under which that liability arises, to convert all or part of that liability into shares, securities or obligations of that person or any other person, to provide that any such contract or instrument is to have effect as if a right had been exercised under it or to suspend any obligation in respect of that liability or any of the powers under that Bail-In Legislation that are related to or ancillary to any of those powers.

SECTION 1.02 Classification of Loans and Borrowings. For purposes of this Agreement, Loans may be classified and referred to by Type (e.g., a "Term Benchmark Loan" or an "RFR Loan"). Borrowings also may be classified and referred to by Type (e.g., a "Term Benchmark Borrowing" or an "RFR Borrowing").

SECTION 1.03 Terms Generally. The definitions of terms herein shall apply equally to the singular and plural forms of the terms defined. Whenever the context may require, any pronoun shall include the corresponding masculine, feminine and neuter forms. The words "include", "includes" and "including" shall be deemed to be followed by the phrase "without limitation". The word "will" shall be construed to have the same meaning and effect as the word "shall". The word "law" shall be construed as referring to all statutes, rules, regulations, codes and other laws (including official rulings and interpretations thereunder having the force of law or with which affected Persons customarily comply), and all judgments, orders and decrees, of all Governmental Authorities. Unless the context requires otherwise (a) any definition of or reference to any agreement, instrument or other document herein shall be construed as referring to such agreement, instrument or other document as from time to time amended, restated, supplemented or otherwise modified (subject to any restrictions on such amendments, restatements, supplements or modifications set forth herein), (b) any reference herein to any Person shall be construed to include such Person's successors and assigns (subject to any restrictions on assignment set forth herein) and, in the case of any Governmental Authority, any other Governmental Authority that shall have succeeded to any or all functions thereof, (c) the words "herein", "hereof" and "hereunder", and words of similar import, shall be construed to refer to this Agreement in its entirety and not to any particular provision hereof, (d) all references herein to Articles, Sections, Exhibits and Schedules shall be construed to refer to Articles and Sections of, and Exhibits and Schedules to, this Agreement, (e) any reference to any law, rule or regulation herein shall, unless otherwise specified, refer to such law, rule or regulation as amended, modified or supplemented from time to time and (f) the words "asset" and "property" shall be construed to have the same meaning and effect and to refer to any and all tangible and intangible assets and properties, including cash, securities, accounts and contract rights.

SECTION 1.04 Accounting Terms; GAAP; Pro Forma Calculations. (a) Except as otherwise expressly provided herein, all terms of an accounting or financial nature shall be construed in accordance with GAAP, as in effect from time to time; provided that, if the Borrower notifies the Administrative Agent that the Borrower requests an amendment to any provision hereof to eliminate the effect of any change occurring after the date hereof in GAAP or in the application thereof on the operation of such provision (or if the Administrative Agent notifies the Borrower that the Required Lenders request an amendment to any provision hereof for such purpose), regardless of whether any such notice is given before or after such change in GAAP or in the application thereof, then such provision shall be interpreted on the basis of GAAP as in effect and applied immediately before such change shall have become effective until such notice shall have been withdrawn or such provision amended in accordance herewith. Notwithstanding any other provision contained herein, all terms of an accounting or financial nature used herein shall be construed, and all computations of amounts and ratios referred to herein shall be made without giving effect to (i) any election under Financial Accounting Standards Board Accounting Standards Codification 825 (or any other Financial Accounting Standard having a similar result or effect) to value any Indebtedness or other liabilities of the Borrower or any Subsidiary at "fair value", as defined therein and (ii) any treatment of Indebtedness in respect of convertible debt instruments under Accounting Standards Codification 470-20 (or any other Accounting Standards Codification or Financial Accounting Standard having a similar result or effect) to value any such Indebtedness in a reduced or bifurcated manner as described therein, and such Indebtedness shall at all times be valued at the full stated principal amount thereof.

(b) All pro forma computations required to be made hereunder giving effect to any acquisition or disposition, or issuance, incurrence or assumption of Indebtedness, or other transaction shall in each case be calculated giving pro forma effect thereto (and, in the case of any pro forma computation made hereunder to determine whether such acquisition or disposition, or issuance, incurrence or assumption of Indebtedness, or other transaction is permitted to be consummated hereunder, to any other such transaction consummated since the first day of the period covered by any component of such pro forma computation and on or prior to the date of such computation) as if such transaction had occurred on the first day of the period of four consecutive fiscal quarters ending with the most recent fiscal quarter for which financial statements shall have been delivered pursuant to Section 5.01(a) or 5.01(b) (or, prior to the delivery of any such financial statements, ending with the last fiscal quarter included in the financial statements referred to in Section 3.03(a)), and, to the extent applicable, to the historical earnings and cash flows associated with the assets acquired or disposed of (but without giving effect to any synergies or cost savings) and any related incurrence or reduction of Indebtedness, all in accordance with Article 11 of Regulation S-X under the Securities Act. If any Indebtedness bears a floating rate of interest and is being given pro forma effect, the interest on such Indebtedness shall be calculated as if the rate in effect on the date of determination had been the applicable rate for the entire period (taking into account any Swap Agreement applicable to such Indebtedness).

(c) Notwithstanding anything to the contrary contained in Section 1.04(a), any change in accounting for leases pursuant to GAAP resulting from the adoption of Financial Accounting Standards Board Accounting Standards Update No. 2016-02, Leases (Topic 842) ("FAS 842"), to the extent such adoption would require treating any lease (or similar arrangement conveying the right to use) as a capital lease where such lease (or similar arrangement) would not have been required to be so treated under GAAP as in effect on December 31, 2015, such lease shall not be considered a capital lease, and all calculations (including with respect to assets and liabilities associated with such lease) and deliverables under this Agreement or any other Loan Document shall be made or delivered, as applicable, in accordance therewith.

SECTION 1.05 Interest Rates; Benchmark Notification. The interest rate on a Loan denominated in Dollars may be derived from an interest rate benchmark that may be discontinued or is, or may in the future become, the subject of regulatory reform. Upon the occurrence of a Benchmark Transition Event, Section 2.14(b) provides a mechanism for determining an alternative rate of interest. The Administrative Agent does not warrant or accept any responsibility for, and shall not have any liability with respect to, the administration, submission, performance or any other matter related to any interest rate used in this Agreement, or with respect to any alternative or successor rate thereto, or replacement rate thereof, including without limitation, whether the composition or characteristics of any such alternative, successor or replacement reference rate will be similar to, or produce the same value or economic equivalence of, the existing interest rate being replaced or have the same volume or liquidity as did any existing interest rate prior to its discontinuance or unavailability. The Administrative Agent and its affiliates and/or other related entities may engage in transactions that affect the calculation of any interest rate used in this Agreement or any alternative, successor or alternative rate (including any Benchmark Replacement) and/or any relevant adjustments thereto, in each case, in a manner adverse to the Borrower. The Administrative Agent may select information sources or services in its reasonable discretion to ascertain any interest rate used in this Agreement, any component thereof, or rates referenced in the definition thereof, in each case pursuant to the terms of this Agreement, and shall have no liability to the Borrower, any Lender or any other Person or entity for damages of any kind, including direct or indirect, special, punitive, incidental or consequential damages, costs, losses or expenses (whether in tort, contract or otherwise and whether at law or in equity), for any error or calculation of any such rate (or component thereof) provided by any such information source or service.

SECTION 1.06 Divisions. For all purposes under the Loan Documents, in connection with any division or plan of division under Delaware law (or any comparable event under a different jurisdiction's laws): (a) if any asset, right, obligation or liability of any Person becomes the asset, right, obligation or liability of a different Person, then it shall be deemed to have been transferred from the original Person to the subsequent Person, and (b) if any new Person comes into existence, such new Person shall be deemed to have been organized and acquired on the first date of its existence by the holders of its Equity Interests at such time.

SECTION 1.07 Amendment and Restatement.

(a) The parties to this Agreement agree that, on the Restatement Effective Date, the terms and provisions of the Existing Credit Agreement shall be and hereby are amended, superseded and restated in their entirety by the terms and provisions of this Agreement. Neither the execution, delivery and acceptance of this Agreement nor any of the terms, covenants, conditions or other provisions set forth herein are intended, nor shall they be deemed or construed, to effect a novation of any liens or indebtedness or other obligations under the Existing Credit Agreement or any other Loan Document (as defined in the Existing Credit Agreement) or to pay, extinguish, release, satisfy or discharge (i) all or any part of the indebtedness or other obligations evidenced by the Existing Credit Agreement, (ii) the liability of any Person under the Existing Credit Agreement or the Loan Documents (as defined under the Existing Credit Agreement) executed and delivered in connection therewith or (iii) the liability of any Person with respect to the Existing Credit Agreement or any indebtedness or other obligations evidenced thereby. All Loans made, and Obligations incurred, under the Existing Credit Agreement which are outstanding on the Restatement Effective Date (and not terminated or otherwise repaid with the proceeds of any Loans made hereunder on the Restatement Effective Date) shall be re-evidenced as Loans and Obligations, respectively, under (and shall be governed by the terms of) this Agreement and the other Loan Documents.

(b) Without limiting the foregoing, upon the effectiveness of the amendment and restatement contemplated hereby on the Restatement Effective Date and except as otherwise expressly provided herein:

(i) all references in the "Loan Documents" (as defined in the Existing Credit Agreement) to the "Administrative Agent", the "Credit Agreement" and the "Loan Documents" shall be deemed to refer to the Administrative Agent, this Agreement and the Loan Documents;

(ii) the "Commitments" and the "Letter of Credit Commitments" (as defined in the Existing Credit Agreement) shall continue as Commitments and Letter of Credit Commitments, respectively, hereunder as set forth on the applicable Commitment Schedule;

(iii) the "Loans" (as defined in the Existing Credit Agreement) outstanding under the Existing Credit Agreement, if any, shall continue as Loans hereunder;

(iv) the Administrative Agent shall make such reallocations, sales, assignments or other relevant actions in respect of the applicable "Commitments" and "Revolving Credit Exposure" (each as defined in and in effect under the Existing Credit Agreement) as are necessary in order that each Lender's Revolving Credit Exposure hereunder reflects such Lender's Applicable Percentage thereof on the Restatement Effective Date (and in no event exceeds each such Lender's Commitment hereunder), and the Borrower and each Lender that was a "Lender" under the Existing Credit Agreement (constituting the "Required Lenders" under and as defined therein) hereby agrees (with effect immediately prior to the Restatement Effective Date) that (x) such reallocation, sales and assignments shall be deemed to have been effected by way of, and subject to the terms and conditions of, Assignment and Assumptions, without the payment of any related assignment fee, and no other documents or instruments shall be, or shall be required to be, executed in connection with such assignments (all of which are hereby waived), (y) such reallocation shall satisfy the assignment provisions of Section 9.04 of the Existing Credit Agreement and (z) in connection with such reallocation, sales, assignments or other relevant actions, the Borrower shall pay all interest and fees outstanding under the Existing Credit Agreement and accrued to the date hereof to the Administrative Agent for the account of the Lenders party hereto, together with any losses, costs and expenses incurred by Lenders under Section 2.16 of the Existing Credit Agreement; and

(v) each of the signatories hereto that is also a party to the Existing Credit Agreement hereby consents to any of the actions described in the foregoing clause (iv) and agrees that any and all required notices and required notice periods under the Existing Credit Agreement in connection with any of the actions described in the foregoing clause (iv) on the Restatement Effective Date are hereby waived and of no force and effect.

SECTION 1.08 Sustainability Adjustments.

(a) Following the date on which the Borrower provides a Pricing Certificate in respect of any Reference Year, (i) the per annum rates set forth under the captions "Term Benchmark Spread" (including with respect to the Letter of Credit fees payable pursuant to Section 2.12(b)(i)) and

"ABR Spread" in the definition of Applicable Rate shall be increased or decreased (or neither increased nor decreased), as applicable, pursuant to the Sustainability Rate Adjustment as set forth in such Pricing Certificate, and (ii) the per annum rates set forth under the caption "Facility Fee Rate" in the definition of Applicable Rate shall be increased or decreased (or neither increased nor decreased), as applicable, pursuant to the Sustainability Facility Fee Adjustment as set forth in such Pricing Certificate. For purposes of the foregoing, (A) the Sustainability Rate Adjustment and the Sustainability Facility Fee Adjustment shall be determined as of the fifth Business Day following receipt by the Administrative Agent of a Pricing Certificate delivered pursuant to Section 1.08(f) based upon the KPI Metrics set forth in such Pricing Certificate and the calculations of the Sustainability Rate Adjustment and the Sustainability Facility Fee Adjustment, therein (such day, the "Sustainability Pricing Adjustment Date") and (B) each change in the Applicable Rate resulting from a Pricing Certificate shall be effective during the period commencing on and including the applicable Sustainability Pricing Adjustment Date and ending on the date immediately preceding the next such Sustainability Pricing Adjustment Date (or, in the case of non-delivery of a Pricing Certificate, the last day such Pricing Certificate could have been delivered pursuant to the terms of Section 1.08(f)).

(b) For the avoidance of doubt, only one Pricing Certificate may be delivered in respect of any Reference Year. It is further understood and agreed that the per annum rates set forth under the captions "Term Benchmark Spread" (including with respect to the Letter of Credit fees payable pursuant to Section 2.12(b)(i)) and "ABR Spread" in the definition of Applicable Rate will never be reduced or increased by more than 0.040% and that the per annum rates set forth under the caption "Facility Fee Rate" in the definition of Applicable Rate will never be reduced or increased by more than 0.010%, pursuant to the Sustainability Rate Adjustment and the Sustainability Facility Fee Adjustment, respectively, during any Reference Year. For the avoidance of doubt, any adjustment to the Applicable Rate shall not be cumulative year-over-year. Each applicable adjustment shall only apply until the date on which the next adjustment is due to take place. Notwithstanding anything to the contrary in this Agreement, the Sustainability Rate Adjustment and the Sustainability Fee Adjustment shall be 0.000% at all times from and after June 30, 2027.

(c) It is hereby understood and agreed that if no such Pricing Certificate is delivered by the Borrower with regard to a particular Reference Year within the period set forth in Section 1.08(f), the Sustainability Rate Adjustment will be positive 0.040% and the Sustainability Facility Fee Adjustment will be positive 0.010% commencing on the last day such Pricing Certificate could have been delivered pursuant to the terms of Section 1.08(f) and continuing until the Borrower delivers Pricing Certificate to the Administrative Agent for the applicable Reference Year.

(d) If (i)(A) the Borrower or any Lender becomes aware of any material inaccuracy in the Sustainability Rate Adjustment, the Sustainability Facility Fee Adjustment or the KPI Metrics as reported in a Pricing Certificate (any such material inaccuracy, a "Pricing Certificate Inaccuracy") and, in the case of any Lender, such Lender delivers, not later than 10 Business Days after obtaining knowledge thereof, a written notice to the Administrative Agent describing such Pricing Certificate Inaccuracy in reasonable detail (which description shall be shared with each Lender and the Borrower), or (B) the Borrower and the Administrative Agent shall mutually agree that there was a Pricing Certificate Inaccuracy at the time of delivery of a Pricing Certificate, and (ii) a proper calculation of the Sustainability Rate Adjustment, Sustainability Facility Fee Adjustment or the KPI Metrics would have resulted in an increase in the Applicable Rate for any period, the Borrower shall be obligated to pay to the Administrative Agent for the account of the applicable Lenders or the applicable L/C Issuers, as the case may be, promptly on demand by the Administrative Agent (or, after the occurrence of an actual or deemed entry of an order for relief with respect to any Borrower under the Bankruptcy Code (or any comparable event under non-U.S. Debtor Relief Laws), automatically and without further action by the Administrative Agent, any Lender or any L/C Issuer), but in any event within 10 Business Days after the Borrower has received written notice of, or has agreed in writing that there was, a Pricing Certificate Inaccuracy, an amount equal to the excess of (1) the amount of interest and fees that should have been paid for such period over (2) the amount of interest and fees actually paid for such period.

(e) It is understood and agreed that any Pricing Certificate Inaccuracy shall not constitute a Default or Event of Default; provided, that, the Borrower complies with the terms of the immediately preceding paragraph with respect to such Pricing Certificate Inaccuracy. Notwithstanding anything to the contrary herein, unless such amounts shall be due upon the occurrence of an actual or deemed entry of an order for relief with respect to a Borrower under the Bankruptcy Code (or any comparable event under non-U.S. Debtor Relief Laws), (a) any additional amounts required to be paid pursuant to the immediately preceding paragraph shall not be due and payable until the earlier to occur of (i) a written demand is made for such payment by the Administrative Agent in accordance with such paragraph or (ii) 10 Business Days after the Borrower has received written notice of, or has agreed in writing that there was, a Pricing Certificate Inaccuracy (such date, the "Certificate Inaccuracy Payment Date"), (b) any nonpayment of such additional amounts prior to the Certificate Inaccuracy Payment Date shall not constitute a Default (whether retroactively or otherwise) and (c) none of such additional amounts shall be deemed overdue prior to the Certificate Inaccuracy Payment Date or shall accrue interest at the Default Rate prior to the Certificate Inaccuracy Payment Date.

(f) Each party hereto hereby agrees that neither the Sustainability Structuring Agent nor the Administrative Agent shall have any responsibility for (or liability in respect of) reviewing, auditing or otherwise evaluating any calculation by the Borrower of any Sustainability Rate Adjustment or Sustainability Facility Fee Adjustment (or any of the data or computations that are part of or related to any such calculation) set forth in any Pricing Certificate (and the Administrative Agent and the Lenders may rely conclusively on any such certificate, without further inquiry).

(g) As soon as available and in any event within 180 days following the end of each fiscal year of the Borrower (commencing with the fiscal year ending December 31, 2021), the Borrower shall deliver to the Administrative Agent and the Lenders, in form and detail satisfactory to the Administrative Agent and the Required Lenders: a Pricing Certificate for the most recently-ended Reference Year; provided, that, for any Reference Year the Borrower may elect not to deliver a Pricing Certificate, and such election shall not constitute a Default or Event of Default (but such failure to so deliver a Pricing Certificate by the end of such 180-day period shall result in the Sustainability Rate Adjustment being applied as set forth in Section 1.08(c).

SECTION 1.09 Letter of Credit Amounts. Unless otherwise specified herein, the amount of a Letter of Credit at any time shall be deemed to be the amount of such Letter of Credit available to be drawn at such time; provided that with respect to any Letter of Credit that, by its terms or the terms of any Letter of Credit Agreement related thereto, provides for one or more automatic increases in the available amount thereof, the amount of such Letter of Credit shall be deemed to be the maximum amount of such Letter of Credit after giving effect to all such increases, whether or not such maximum amount is available to be drawn at such time.

ARTICLE II

The Credits

SECTION 2.01 Commitments. Subject to the terms and conditions set forth herein, each Lender (severally and not jointly) agrees to make Revolving Loans to the Borrower in Dollars from time to time during the Availability Period in an aggregate principal amount that will not result (after giving effect to any application of proceeds of such Borrowing pursuant to Section 2.10) in (a) such Lender's Revolving Credit Exposure exceeding such Lender's Commitment or (b) the Total Revolving Credit Exposure exceeding the Aggregate Commitment. Within the foregoing limits and subject to the terms and conditions set forth herein, the Borrower may borrow, prepay and reborrow Revolving Loans.

SECTION 2.02 Loans and Borrowings. (a) Each Revolving Loan shall be made as part of a Borrowing consisting of Revolving Loans made by the Lenders ratably in accordance with their respective Commitments. The failure of any Lender to make any Loan required to be made by it shall not relieve any other Lender of its obligations hereunder; provided that the Commitments of the Lenders are several and no Lender shall be responsible for any other Lender's failure to make Loans as required.

(b) Subject to Section 2.14, each Revolving Borrowing shall be comprised entirely of ABR Loans, Term Benchmark Loans or RFR Loans as the Borrower may request in accordance herewith. Each Lender at its option may make any Term Benchmark Loan by causing any domestic or foreign branch or Affiliate of such Lender to make such Loan (and in the case of an Affiliate, the provisions of Sections 2.14, 2.15, 2.16 and 2.17 shall apply to such Affiliate to the same extent as to such Lender); provided that any exercise of such option shall not affect the obligation of the Borrower to repay such Loan in accordance with the terms of this Agreement.

(c) At the commencement of each Interest Period for any Term Benchmark Revolving Borrowing, such Borrowing shall be in an aggregate amount that is an integral multiple of $1,000,000 thereof. At the time that each ABR Revolving Borrowing and/or RFR Borrowing is made, such Borrowing shall be in an aggregate amount that is an integral multiple of $1,000,000; provided that an ABR Revolving Borrowing may be in an aggregate amount that is equal to the entire unused balance of the Aggregate Commitment or that is required to finance the reimbursement of an LC Disbursement as contemplated by Section 2.06(e). Borrowings of more than one Type may be outstanding at the same time; provided that there shall not at any time be more than a total of eight (8) Term Benchmark Borrowings or RFR Borrowings outstanding.

(d) Notwithstanding any other provision of this Agreement, the Borrower shall not be entitled to request, or to elect to convert or continue, any Borrowing if the Interest Period requested with respect thereto would end after the Maturity Date.

SECTION 2.03 Requests for Revolving Borrowings. To request a Revolving Borrowing, the Borrower shall notify the Administrative Agent of such request by submitting a Borrowing Request (a)(i) in the case of a Term Benchmark Borrowing, not later than 11:00 a.m., New York City time, three (3) U.S. Government Securities Business Days before the date of the proposed Borrowing or (ii) in the case of an RFR Borrowing, not later than 11:00 a.m., New York City time, five (5) U.S. Government Securities Business Days before the date of the proposed Borrowing or (b) in the case of an ABR Borrowing, not later than 1:00 p.m., New York City time, on the date of the proposed Borrowing; provided that any such notice of an ABR Revolving Borrowing to finance the reimbursement of an LC Disbursement as contemplated by Section 2.06(e) may be given not later than 10:00 a.m., New York City time, on the date of the proposed Borrowing. Each such Borrowing Request shall be irrevocable and shall be signed by an Authorized Officer of the Borrower. Each such Borrowing Request shall specify the following information in compliance with Section 2.02:

(i) the aggregate principal amount of the requested Borrowing;

(ii) the date of such Borrowing, which shall be a Business Day;

(iii) whether such Borrowing is to be an ABR Borrowing, a Term Benchmark Borrowing or an RFR Borrowing;

(iv) in the case of a Term Benchmark Borrowing, the initial Interest Period to be applicable thereto, which shall be a period contemplated by the definition of the term "Interest Period"; and

(v) the location and number of the Borrower's account to which funds are to be disbursed, which shall comply with the requirements of Section 2.07.

If no election as to the Type of Revolving Borrowing is specified, then the requested Revolving Borrowing shall be an ABR Borrowing. If no Interest Period is specified with respect to any requested Term Benchmark Revolving Borrowing, then the Borrower shall be deemed to have selected an Interest Period of one month's duration. Promptly following receipt of a Borrowing Request in accordance with this Section, the Administrative Agent shall advise each Lender of the details thereof and of the amount of such Lender's Loan to be made as part of the requested Borrowing. Notwithstanding the foregoing, in no event shall the Borrower be permitted to request pursuant to this Section 2.03 an RFR Loan bearing interest based on Daily Simple SOFR prior to a Benchmark Transition Event and Benchmark Replacement Date with respect to the Term SOFR Rate (it being understood and agreed that Daily Simple SOFR shall only apply to the extent provided in Sections 2.14(a) and 2.14(f).

SECTION 2.04 Intentionally Omitted.

SECTION 2.05 Intentionally Omitted.

SECTION 2.06 Letters of Credit. (a) General. Subject to the terms and conditions set forth herein, the Borrower may request the issuance of Letters of Credit denominated in Dollars as the applicant thereof for the support of its or its Subsidiaries' obligations, in a form reasonably acceptable to the Administrative Agent and the applicable Issuing Bank, at any time and from time to time during the Availability Period. In the event of any inconsistency between the terms and conditions of this Agreement and the terms and conditions of any Letter of Credit Agreement, the terms and conditions of this Agreement shall control. Notwithstanding anything herein to the contrary, no Issuing Bank shall have any obligation hereunder to issue, and shall not issue, any Letter of Credit the proceeds of which would be made available to any Person (i) to fund any activity or business of or with any Sanctioned Person, or in any country or territory that, at the time of such funding, is the subject of any Sanctions, (ii) in any manner that would result in a violation of any Sanctions by any party to this Agreement or (iii) in any manner that would result in a violation of one or more policies of such Issuing Bank applicable to letters of credit generally.

(b) Notice of Issuance, Amendment, Renewal, Extension; Certain Conditions. To request the issuance of a Letter of Credit (or the amendment, renewal or extension of an outstanding Letter of Credit), the Borrower shall hand deliver or telecopy (or transmit by electronic communication, if arrangements for doing so have been approved by the applicable Issuing Bank) to the applicable Issuing Bank and the Administrative Agent (reasonably in advance of the requested date of issuance, amendment, renewal or extension, but in any event no less than three (3) Business Days) a notice requesting the issuance of a Letter of Credit, or identifying the Letter of Credit to be amended, renewed or extended, and specifying the date of issuance, amendment, renewal or extension (which shall be a Business Day), the date on which such Letter of Credit is to expire (which shall comply with paragraph (c) of this Section), the amount of such Letter of Credit, the name and address of the beneficiary thereof and such other information as shall be necessary to prepare, amend, renew or extend such Letter of Credit. In addition, as a condition to any such Letter of Credit issuance, the Borrower shall have entered into a continuing agreement (or other letter of credit agreement) for the issuance of letters of credit and/or shall submit a letter of credit application, in each case, as required by the applicable Issuing Bank and using such Issuing Bank's standard form (each, a "Letter of Credit Agreement"). A Letter of Credit shall be issued, amended, renewed or extended only if (and upon issuance, amendment, renewal or extension of each Letter of Credit the Borrower shall be deemed to represent and warrant that), after giving effect to such issuance, amendment, renewal or extension (i) (x) the aggregate undrawn amount of all outstanding Letters of Credit issued by any Issuing Bank at such time plus (y) the aggregate amount of all LC Disbursements made by such Issuing Bank that have not yet been reimbursed by or on behalf of the Borrower at such time shall not exceed such Issuing Bank's Letter of Credit Commitment, (ii) the LC Exposure shall not exceed $40,000,000, (iii) no Lender's Revolving Credit Exposure shall exceed its Commitment, and (iv) the Total Revolving Credit Exposure shall not exceed the Aggregate Commitment. The Borrower may, at any time and from time to time, reduce the Letter of Credit Commitment of any Issuing Bank with the consent of such Issuing Bank; provided that the Borrower shall not reduce the Letter of Credit Commitment of any Issuing Bank if, after giving effect of such reduction, the conditions set forth in clauses (i) through (iv) above shall not be satisfied.

An Issuing Bank shall not be under any obligation to issue any Letter of Credit if:

(i) any order, judgment or decree of any Governmental Authority or arbitrator shall by its terms purport to enjoin or restrain such Issuing Bank from issuing such Letter of Credit, or any law applicable to such Issuing Bank shall prohibit, or require that such Issuing Bank refrain from, the issuance of letters of credit generally or such Letter of Credit in particular or shall impose upon such Issuing Bank with respect to such Letter of Credit any restriction, reserve or capital or liquidity requirement (for which such Issuing Bank is not otherwise compensated hereunder) not in effect on the Restatement Effective Date, or shall impose upon such Issuing Bank any unreimbursed loss, cost or expense that was not applicable on the Restatement Effective Date and that such Issuing Bank in good faith deems material to it; or

(ii) the issuance of such Letter of Credit would violate one or more policies of such Issuing Bank applicable to letters of credit generally.

(c) Expiration Date. Each Letter of Credit shall expire (or be subject to termination by notice from the applicable Issuing Bank to the beneficiary thereof) at or prior to the close of business on the earlier of (i) the date one year after the date of the issuance of such Letter of Credit (or, in the case of any renewal or extension thereof, one year after such renewal or extension) and (ii) the date that is five (5) Business Days prior to the Maturity Date.

(d) Participations. By the issuance of a Letter of Credit (or an amendment to a Letter of Credit increasing the amount thereof) and without any further action on the part of the applicable Issuing Bank or the Lenders, such Issuing Bank hereby grants to each Lender, and each Lender hereby acquires from such Issuing Bank, a participation in such Letter of Credit equal to such Lender's Applicable Percentage of the aggregate amount available to be drawn under such Letter of Credit. In consideration and in furtherance of the foregoing, each Lender hereby absolutely and unconditionally agrees to pay to the Administrative Agent, for the account of such Issuing Bank, such Lender's Applicable Percentage of each LC Disbursement made by such Issuing Bank and not reimbursed by the Borrower on the date due as provided in paragraph (e) of this Section, or of any reimbursement payment required to be refunded to the Borrower for any reason. Each Lender acknowledges and agrees that its obligation to acquire participations pursuant to this paragraph in respect of Letters of Credit is absolute and unconditional and shall not be affected by any circumstance whatsoever, including any amendment, renewal or extension of any Letter of Credit or the occurrence and continuance of a Default or reduction or termination of the Commitments, and that each such payment shall be made without any offset, abatement, withholding or reduction whatsoever.

(e) Reimbursement. If any Issuing Bank shall make any LC Disbursement in respect of a Letter of Credit issued by such Issuing Bank, the Borrower shall reimburse such LC Disbursement by paying to the Administrative Agent in Dollars the amount equal to such LC Disbursement, calculated as of the date such Issuing Bank made such LC Disbursement not later than 12:00 noon, New York City time, on the date that such LC Disbursement is made, if the Borrower shall have received notice of such LC Disbursement prior to 10:00 a.m., New York City time, on such date, or, if such notice has not been received by the Borrower prior to such time on such date, then not later than 12:00 noon, New York City time, on the Business Day immediately following the day that the Borrower receives such notice, if such notice is not received prior to such time on the day of receipt; provided that the Borrower may, subject to the conditions to borrowing set forth herein, request in accordance with Section 2.03 that such payment be financed with an ABR Revolving Borrowing in an equivalent amount of such LC Disbursement and, to the extent so financed, the Borrower's obligation to make such payment shall be discharged and replaced by the resulting ABR Revolving Borrowing. If the Borrower fails to make such payment when due, the Administrative Agent shall notify each Lender of the applicable LC Disbursement, the payment then due from the Borrower in respect thereof and such Lender's Applicable Percentage thereof. Promptly following receipt of such notice, each Lender shall pay to the Administrative Agent its Applicable Percentage of the payment then due from the Borrower, in the same manner as provided in Section 2.07 with respect to Loans made by such Lender (and Section 2.07 shall apply, mutatis mutandis, to the payment obligations of the Lenders), and the Administrative Agent shall promptly pay to such Issuing Bank the amounts so received by it from the Lenders. Promptly following receipt by the Administrative Agent of any payment from the Borrower pursuant to this paragraph, the Administrative Agent shall distribute such payment to such Issuing Bank or, to the extent that Lenders have made payments pursuant to this paragraph to reimburse such Issuing Bank, then to such Lenders and such Issuing Bank as their interests may appear. Any payment made by a Lender pursuant to this paragraph to reimburse such Issuing Bank for any LC Disbursement (other than the funding of an ABR Revolving Loan as contemplated above) shall not constitute a Loan and shall not relieve the Borrower of its obligation to reimburse such LC Disbursement.

(f) Obligations Absolute. The Borrower's obligation to reimburse LC Disbursements as provided in paragraph (e) of this Section shall be absolute, unconditional and irrevocable, and shall be performed strictly in accordance with the terms of this Agreement under any and all circumstances whatsoever and irrespective of (i) any lack of validity or enforceability of any Letter of Credit, any Letter of Credit Agreement or this Agreement, or any term or provision therein, (ii) any draft or other document presented under a Letter of Credit proving to be forged, fraudulent or invalid in any respect or any statement therein being untrue or inaccurate in any respect, (iii) payment by any Issuing Bank under a Letter of Credit against presentation of a draft or other document that does not comply with the terms of such Letter of Credit, or (iv) any other event or circumstance whatsoever, whether or not similar to any of the foregoing, that might, but for the provisions of this Section, constitute a legal or equitable discharge of, or provide a right of setoff against, the Borrower's obligations hereunder. Neither the Administrative Agent, the Lenders nor the Issuing Banks, nor any of their Related Parties, shall have any liability or responsibility by reason of or in connection with the issuance or transfer of any Letter of Credit or any payment or failure to make any payment thereunder (irrespective of any of the circumstances referred to in the preceding sentence), or any error, omission, interruption, loss or delay in transmission or delivery of any draft, notice or other communication under or relating to any Letter of Credit (including any document required to make a drawing thereunder), any error in interpretation of technical terms or any consequence arising from causes beyond the control of the applicable Issuing Bank; provided that the foregoing shall not be construed to excuse such Issuing Bank from liability to the Borrower to the extent of any direct damages (as opposed to special, indirect, consequential or punitive damages, claims in respect of which are hereby waived by the Borrower to the extent permitted by applicable law) suffered by the Borrower that are caused by such Issuing Bank's failure to exercise care when determining whether drafts and other documents presented under a Letter of Credit comply with the terms thereof. The parties hereto expressly agree that, in the absence of gross negligence or willful misconduct on the part of an Issuing Bank (as finally determined by a non-appealable judgment of a court of competent jurisdiction), such Issuing Bank shall be deemed to have exercised care in each such determination. In furtherance of the foregoing and without limiting the generality thereof, the parties agree that, with respect to documents presented which appear on their face to be in substantial compliance with the terms of a Letter of Credit, the applicable Issuing Bank may, in its sole discretion, either accept and make payment upon such documents without responsibility for further investigation, regardless of any notice or information to the contrary, or refuse to accept and make payment upon such documents if such documents are not in strict compliance with the terms of such Letter of Credit.

(g) Disbursement Procedures. The applicable Issuing Bank shall, promptly following its receipt thereof, examine all documents purporting to represent a demand for payment under a Letter of Credit. Such Issuing Bank shall promptly notify the Administrative Agent and the Borrower by telephone (confirmed by telecopy or electronic mail) of such demand for payment and whether such Issuing Bank has made or will make an LC Disbursement thereunder; provided that any failure to give or delay in giving such notice shall not relieve the Borrower of its obligation to reimburse such Issuing Bank and the Lenders with respect to any such LC Disbursement.

(h) Interim Interest. If such Issuing Bank shall make any LC Disbursement, then, unless the Borrower shall reimburse such LC Disbursement in full on the date such LC Disbursement is made, the unpaid amount thereof shall bear interest, for each day from and including the date such LC Disbursement is made to but excluding the date that the reimbursement is due and payable, at the rate per annum then applicable to ABR Revolving Loans and such interest shall be due and payable on the date when such reimbursement is payable; provided that, if the Borrower fails to reimburse such LC Disbursement when due pursuant to paragraph (e) of this Section, then Section 2.13(d) shall apply. Interest accrued pursuant to this paragraph shall be for the account of such Issuing Bank, except that interest accrued on and after the date of payment by any Lender pursuant to paragraph (e) of this Section to reimburse such Issuing Bank shall be for the account of such Lender to the extent of such payment.

(i) Replacement and Resignation of Issuing Bank.

(i) Any Issuing Bank may be replaced at any time by written agreement among the Borrower, the Administrative Agent, the replaced Issuing Bank and the successor Issuing Bank. The Administrative Agent shall notify the Lenders of any such replacement of an Issuing Bank. At the time any such replacement shall become effective, the Borrower shall pay all unpaid fees accrued for the account of the replaced Issuing Bank pursuant to Section 2.12(b). From and after the effective date of any such replacement, (i) the successor Issuing Bank shall have all the rights and obligations of the replaced Issuing Bank under this Agreement with respect to Letters of Credit to be issued thereafter and (ii) references herein to the term "Issuing Bank" shall be deemed to refer to such successor or to any previous Issuing Bank, or to such successor and all previous Issuing Banks, as the context shall require. After the replacement of an Issuing Bank hereunder, the replaced Issuing Bank shall remain a party hereto and shall continue to have all the rights and obligations of an Issuing Bank under this Agreement with respect to Letters of Credit then outstanding and issued by it prior to such replacement, but shall not be required to issue additional Letters of Credit or extend or otherwise amend any existing Letter of Credit.

(ii) Subject to the appointment and acceptance of a successor Issuing Bank, any Issuing Bank may resign as an Issuing Bank at any time upon thirty days' prior written notice to the Administrative Agent, the Borrower and the Lenders, in which case, such resigning Issuing Bank shall be replaced in accordance with Section 2.06(i)(i) above.

(j) Cash Collateralization. If any Event of Default shall occur and be continuing, on the Business Day that the Borrower receives notice from the Administrative Agent or the Required Lenders (or, if the maturity of the Loans has been accelerated, Lenders with LC Exposure representing greater than 50% of the total LC Exposure) demanding the deposit of cash collateral pursuant to this paragraph, the Borrower shall deposit in an account with the Administrative Agent, in the name of the Administrative Agent and for the benefit of the Lenders (the "LC Collateral Account"), an amount in cash equal to 100% of the amount of the LC Exposure as of such date plus any accrued and unpaid interest thereon; provided that the obligation to deposit such cash collateral shall become effective immediately, and such deposit shall become immediately due and payable, without demand or other notice of any kind, upon the occurrence of any Event of Default with respect to the Borrower described in Section 7.01(h) or (i). Such deposit shall be held by the Administrative Agent as collateral for the payment and performance of the Obligations. The Administrative Agent shall have exclusive dominion and control, including the exclusive right of withdrawal, over such account and the Borrower hereby grants to the Administrative Agent a security interest in the LC Collateral Account. Other than any interest earned on the investment of such deposits, which investments shall be made at the option and sole discretion of the Administrative Agent and at the Borrower's risk and expense, such deposits shall not bear interest. Interest or profits, if any, on such investments shall accumulate in such account. Moneys in such account shall be applied by the Administrative Agent to reimburse any applicable Issuing Bank for LC Disbursements for which it has not been reimbursed and, to the extent not so applied, shall be held for the satisfaction of the reimbursement obligations of the Borrower for the LC Exposure at such time or, if the maturity of the Loans has been accelerated (but subject to the consent of Lenders with LC Exposure representing greater than 50% of the total LC Exposure), be applied to satisfy other Obligations. If the Borrower is required to provide an amount of cash collateral hereunder as a result of the occurrence of an Event of Default, such amount (to the extent not applied as aforesaid) shall be returned to the Borrower within three (3) Business Days after all Events of Default have been cured or waived.

(k) Letters of Credit Issued for Account of Subsidiaries. Notwithstanding that a Letter of Credit issued or outstanding hereunder supports any obligations of, or is for the account of, a Subsidiary, or states that a Subsidiary is the "account party," "applicant," "customer," "instructing party," or the like of or for such Letter of Credit, and without derogating from any rights of the applicable Issuing Bank (whether arising by contract, at law, in equity or otherwise) against such Subsidiary in respect of such Letter of Credit, the Borrower (i) shall reimburse, indemnify and compensate the applicable Issuing Bank hereunder for such Letter of Credit (including to reimburse any and all drawings thereunder) as if such Letter of Credit had been issued solely for the account of the Borrower and (ii) irrevocably waives any and all defenses that might otherwise be available to it as a guarantor or surety of any or all of the obligations of such Subsidiary in respect of such Letter of Credit. The Borrower hereby acknowledges that the issuance of such Letters of Credit for its Subsidiaries inures to the benefit of the Borrower, and that the Borrower's business derives substantial benefits from the businesses of such Subsidiaries.

(l) Issuing Bank Agreements. Unless otherwise requested by the Administrative Agent, each Issuing Bank shall report in writing to the Administrative Agent (i) promptly following the end of each calendar month, the aggregate amount of Letters of Credit issued by it and outstanding at the end of such month, (ii) on or prior to each Business Day on which such Issuing Bank expects to issue, amend, renew or extend any Letter of Credit, the date of such issuance, amendment, renewal or extension, and the aggregate face amount of the Letter of Credit to be issued, amended, renewed or extended by it and outstanding after giving effect to such issuance, amendment, renewal or extension occurred (and whether the amount thereof changed), it being understood that such Issuing Bank shall not permit any issuance, renewal, extension or amendment resulting in an increase in the amount of any Letter of Credit to occur without first obtaining written confirmation from the Administrative Agent that it is then permitted under this Agreement, (iii) on each Business Day on which such Issuing Bank makes any payment under any Letter of Credit, the date of such payment under such Letter of Credit and the amount of such payment, (iv) on any Business Day on which the Borrower fails to reimburse any payment under any Letter of Credit required to be reimbursed to such Issuing Bank on such day, the date of such failure and the amount of such payment and (v) on any other Business Day, such other information as the Administrative Agent shall reasonably request.

SECTION 2.07 Funding of Borrowings. (a) Each Lender shall make each Loan to be made by it hereunder on the proposed date thereof solely by wire transfer of immediately available funds by 12:00 noon, New York City time (or, with respect to any ABR Borrowing, the Borrowing Request for which shall have been received after 10:00 a.m. but at or before 1:00 p.m., New York City time, by 3:00 p.m., New York City time), to the account of the Administrative Agent most recently designated by it for such purpose by notice to the Lenders. Except in respect of the provisions of this Agreement covering the reimbursement of Letters of Credit, the Administrative Agent will make such Loans available to the Borrower by promptly making available the funds so received in the aforesaid account of the Administrative Agent by wire transfer of immediately available funds to an account of the Borrower designated by the Borrower in the applicable Borrowing Request; provided that ABR Revolving Loans made to finance the reimbursement of an LC Disbursement as provided in Section 2.06(e) shall be remitted by the Administrative Agent to the applicable Issuing Bank.

(b) Unless the Administrative Agent shall have received notice from a Lender prior to the proposed date of any Borrowing that such Lender will not make available to the Administrative Agent such Lender's share of such Borrowing, the Administrative Agent may assume that such Lender has made such share available on such date in accordance with paragraph (a) of this Section and may, in reliance upon such assumption, make available to the Borrower a corresponding amount. In such event, if a Lender has not in fact made its share of the applicable Borrowing available to the Administrative Agent, then the applicable Lender and the Borrower severally agree to pay to the Administrative Agent forthwith on demand such corresponding amount with interest thereon, for each day from and including the date such amount is made available to the Borrower to but excluding the date of payment to the Administrative Agent, at (i) in the case of such Lender, the greater of the NYFRB Rate and a rate determined by the Administrative Agent in accordance with banking industry rules on interbank compensation or (ii) in the case of the Borrower, the interest rate applicable to ABR Loans. If such Lender pays such amount to the Administrative Agent, then such amount shall constitute such Lender's Loan included in such Borrowing.

SECTION 2.08 Interest Elections. (a) Each Revolving Borrowing initially shall be of the Type specified in the applicable Borrowing Request and, in the case of a Term Benchmark Revolving Borrowing, shall have an initial Interest Period as specified in such Borrowing Request. Thereafter, the Borrower may elect to convert such Borrowing to a different Type or to continue such Borrowing and, in the case of a Term Benchmark Revolving Borrowing, may elect Interest Periods therefor, all as provided in this Section. The Borrower may elect different options with respect to different portions of the affected Borrowing, in which case each such portion shall be allocated ratably among the Lenders holding the Loans comprising such Borrowing, and the Loans comprising each such portion shall be considered a separate Borrowing.

(b) To make an election pursuant to this Section, the Borrower shall notify the Administrative Agent of such election by the time that a Borrowing Request would be required under Section 2.03 if the Borrower were requesting a Revolving Borrowing of the Type resulting from such election to be made on the effective date of such election. Each such Interest Election Request shall be irrevocable and shall be signed by an Authorized Officer of the Borrower. Notwithstanding any contrary provision herein, this Section shall not be construed to permit the Borrower to elect an Interest Period for Term Benchmark Loans that does not comply with Section 2.02(d).

(c) Each Interest Election Request shall specify the following information in compliance with Section 2.02:

(i) the Borrowing to which such Interest Election Request applies and, if different options are being elected with respect to different portions thereof, the portions thereof to be allocated to each resulting Borrowing (in which case the information to be specified pursuant to clauses (iii) and (iv) below shall be specified for each resulting Borrowing);

(ii) the effective date of the election made pursuant to such Interest Election Request, which shall be a Business Day;

(iii) whether the resulting Borrowing is to be an ABR Borrowing or a Term Benchmark Borrowing or an RFR Borrowing; and

(iv) if the resulting Borrowing is a Term Benchmark Borrowing, the Interest Period to be applicable thereto after giving effect to such election, which Interest Period shall be a period contemplated by the definition of the term "Interest Period".

If any such Interest Election Request requests a Term Benchmark Borrowing but does not specify an Interest Period, then the Borrower shall be deemed to have selected an Interest Period of one month's duration. Notwithstanding the foregoing, in no event shall the Borrower be permitted to request an RFR Loan bearing interest based on Daily Simple SOFR prior to a Benchmark Transition Event and Benchmark Replacement Date with respect to the Term SOFR Rate (it being understood and agreed that Daily Simple SOFR shall only apply to the extent provided in Sections 2.14(a) and 2.14(f).

(d) Promptly following receipt of an Interest Election Request, the Administrative Agent shall advise each Lender of the details thereof and of such Lender's portion of each resulting Borrowing.

(e) If the Borrower fails to deliver a timely Interest Election Request with respect to a Term Benchmark Revolving Borrowing prior to the end of the Interest Period applicable thereto, then, unless such Borrowing is repaid as provided herein, at the end of such Interest Period such Borrowing shall be converted to an ABR Borrowing. Notwithstanding any contrary provision hereof, if an Event of Default has occurred and is continuing and the Administrative Agent, at the request of the Required Lenders, so notifies the Borrower, then, so long as an Event of Default is continuing (i) no outstanding Revolving Borrowing may be converted to or continued as a Term Benchmark Borrowing and (ii) unless repaid, each Term Benchmark Revolving Borrowing shall be converted to an ABR Borrowing at the end of the Interest Period applicable thereto.

(f) Notwithstanding anything in this Agreement or any other Loan Document to the contrary, interest on all "Term Benchmark Loans" outstanding immediately prior to the Amendment No. 1 Effective Date shall continue to accrue and be paid based upon the "LIBO Rate" applicable pursuant to the terms of the Credit Agreement immediately prior to the Amendment No. 1 Effective Date solely until the expiration of the current "Interest Period" (as defined in the Credit Agreement immediately prior to the Amendment No. 1 Effective Date and taking into account any grace periods or extensions of such "Interest Period" approved immediately prior to the Amendment No. 1 Effective Date) applicable thereto (at which time such Term Benchmark Loans may be reborrowed as Term Benchmark Borrowings or converted to ABR Borrowings in accordance with this section 2.08); provided, however, that from and after the Amendment No. 1 Effective Date, the Applicable Rate to be applied to any such Term Benchmark Loans shall be based on the Applicable Rate for Term Benchmark Loans after the Amendment No. 1 Effective Date.

SECTION 2.09 Termination and Reduction of Commitments. (a) Unless previously terminated, the Commitments shall terminate on the Maturity Date.

(b) The Borrower may at any time terminate, or from time to time reduce, the Commitments; provided that (i) each reduction of the Commitments shall be in an amount that is an integral multiple of $1,000,000 and not less than $5,000,000 and (ii) the Borrower shall not terminate or reduce the Commitments if, after giving effect to any concurrent prepayment of the Loans in accordance with Section 2.11, the Total Revolving Credit Exposure would exceed the Aggregate Commitment.

(c) The Borrower shall notify the Administrative Agent of any election to terminate or reduce the Commitments under paragraph (b) of this Section at least three (3) Business Days prior to the effective date of such termination or reduction, specifying such election and the effective date thereof. Promptly following receipt of any notice, the Administrative Agent shall advise the Lenders of the contents thereof. Each notice delivered by the Borrower pursuant to this Section shall be irrevocable; provided that a notice of termination of the Commitments delivered by the Borrower may state that such notice is conditioned upon the effectiveness of other credit facilities or other transactions specified therein, in which case such notice may be revoked by the Borrower (by notice to the Administrative Agent on or prior to the specified effective date) if such condition is not satisfied. Any termination or reduction of the Commitments shall be permanent. Each reduction of the Commitments shall be made ratably among the Lenders in accordance with their respective Commitments.

SECTION 2.10 Repayment of Loans; Evidence of Debt. (a) The Borrower hereby unconditionally promises to pay to the Administrative Agent for the account of each Lender the then unpaid principal amount of each Revolving Loan on the Maturity Date.

(b) Each Lender shall maintain in accordance with its usual practice an account or accounts evidencing the indebtedness of the Borrower to such Lender resulting from each Loan made by such Lender, including the amounts of principal and interest payable and paid to such Lender from time to time hereunder.

(c) The Administrative Agent shall maintain accounts in which it shall record (i) the amount of each Loan made hereunder, the Type thereof and the Interest Period applicable thereto, (ii) the amount of any principal or interest due and payable or to become due and payable from the Borrower to each Lender hereunder and (iii) the amount of any sum received by the Administrative Agent hereunder for the account of the Lenders and each Lender's share thereof.

(d) The entries made in the accounts maintained pursuant to paragraph (b) or (c) of this Section shall be prima facie evidence of the existence and amounts of the obligations recorded therein; provided that the failure of any Lender or the Administrative Agent to maintain such accounts or any error therein shall not in any manner affect the obligation of the Borrower to repay the Loans in accordance with the terms of this Agreement.

(e) Any Lender may request that Loans made by it be evidenced by a promissory note. In such event, the Borrower shall prepare, execute and deliver to such Lender a promissory note payable to such Lender (or, if requested by such Lender, to such Lender and its registered assigns) and in a form approved by the Administrative Agent. Thereafter, the Loans evidenced by such promissory note and interest thereon shall at all times (including after assignment pursuant to Section 9.04) be represented by one or more promissory notes in such form.

SECTION 2.11 Prepayment of Loans. The Borrower shall have the right at any time and from time to time to prepay any Borrowing in whole or in part, subject to prior notice in accordance with the provisions of this Section 2.11. The Borrower shall notify the Administrative Agent by telephone (confirmed by telecopy or electronic mail) of any prepayment hereunder (i) in the case of prepayment of (x) a Term Benchmark Revolving Borrowing, not later than 11:00 a.m., New York City time, three (3) Business Days before the date of prepayment or (y) an RFR Revolving Borrowing , not later than 11:00 a.m. New York City time, five (5) Business Days before the date of prepayment, (ii) in the case of prepayment of an ABR Revolving Borrowing, not later than 11:00 a.m., New York City time, one (1) Business Day before the date of prepayment. Each such notice shall be irrevocable and shall specify the prepayment date and the principal amount of each Borrowing or portion thereof to be prepaid; provided that, if a notice of prepayment is given in connection with a conditional notice of termination of the Commitments as contemplated by Section 2.09, then such notice of prepayment may be revoked if such notice of termination is revoked in accordance with Section 2.09. Promptly following receipt of any such notice relating to a Revolving Borrowing, the Administrative Agent shall advise the Lenders of the contents thereof. Each partial prepayment of any Revolving Borrowing shall be in an amount that would be permitted in the case of an advance of a Revolving Borrowing of the same Type as provided in Section 2.02. Each prepayment of a Revolving Borrowing shall be applied ratably to the Loans included in the prepaid Borrowing. Prepayments shall be accompanied by (i) accrued interest to the extent required by Section 2.13 and (ii) break funding payments pursuant to Section 2.16. If at any time the sum of the aggregate principal amount of all of the Revolving Credit Exposures exceeds the Aggregate Commitment, the Borrower shall immediately repay Borrowings or cash collateralize LC Exposure in an account with the Administrative Agent pursuant to Section 2.06(j), as applicable, in an aggregate principal amount sufficient to cause the aggregate principal amount of all Revolving Credit Exposures to be less than or equal to the Aggregate Commitment.

SECTION 2.12 Fees. (a) The Borrower agrees to pay to the Administrative Agent for the account of each Lender a facility fee, which shall accrue at the Applicable Rate on the daily amount of the Commitment of such Lender (whether used or unused) during the period from and including the Restatement Effective Date to but excluding the date on which such Commitment terminates; provided that, if such Lender continues to have any Revolving Credit Exposure after its Commitment terminates, then such facility fee shall continue to accrue on the daily amount of such Lender's Revolving Credit Exposure from and including the date on which its Commitment terminates to but excluding the date on which such Lender ceases to have any Revolving Credit Exposure. Facility fees accrued through and including the last day of March, June, September and December of each year shall be payable in arrears on the fifteenth day following the such last day and on the date on which the Commitments terminate, commencing on the first such date to occur after the date hereof; provided that any facility fees accruing after the date on which the Commitments terminate shall be payable on demand. All facility fees shall be computed on the basis of a year of 360 days and shall be payable for the actual number of days elapsed (including the first day but excluding the last day).

(b) The Borrower agrees to pay (i) to the Administrative Agent for the account of each Lender a participation fee with respect to its participations in Letters of Credit, which shall accrue at the same Applicable Rate used to determine the interest rate applicable to Term Benchmark Revolving Loans on the average daily amount of such Lender's LC Exposure (excluding any portion thereof attributable to unreimbursed LC Disbursements) during the period from and including the Restatement Effective Date to but excluding the later of the date on which such Lender's Commitment terminates and the date on which such Lender ceases to have any LC Exposure and (ii) to each Issuing Bank for its own account a fronting fee, which shall accrue at the rate or rates per annum separately agreed upon between the Borrower and such Issuing Bank on the average daily amount of the LC Exposure (excluding any portion thereof attributable to unreimbursed LC Disbursements) attributable to Letters of Credit issued by such Issuing Bank during the period from and including the Restatement Effective Date to but excluding the later of the date of termination of the Commitments and the date on which there ceases to be any LC Exposure, as well as such Issuing Bank's standard fees and commissions with respect to the issuance, amendment, cancellation, negotiation, transfer, presentment, renewal or extension of any Letter of Credit or processing of drawings thereunder. Participation fees and fronting fees accrued through and including the last day of March, June, September and December of each year shall be payable on the fifteenth day following such last day, commencing on the first such date to occur after the Restatement Effective Date; provided that all such fees shall be payable on the date on which the Commitments terminate and any such fees accruing after the date on which the Commitments terminate shall be payable on demand. Any other fees payable to any Issuing Bank pursuant to this paragraph shall be payable within ten (10) days after demand. All participation fees and fronting fees shall be computed on the basis of a year of 360 days and shall be payable for the actual number of days elapsed (including the first day but excluding the last day).

(c) The Borrower agrees to pay to the Administrative Agent, for its own account, fees payable in the amounts and at the times separately agreed upon between the Borrower and the Administrative Agent.

(d) All fees payable hereunder shall be paid on the dates due, in immediately available funds, to the Administrative Agent (or to an Issuing Bank, in the case of fees payable to it) for distribution, in the case of facility fees and participation fees, to the Lenders. Fees paid shall not be refundable under any circumstances.

SECTION 2.13 Interest. (a) The Loans comprising each ABR Borrowing shall bear interest at the Alternate Base Rate plus the Applicable Rate.

(b) The Loans comprising each Term Benchmark Borrowing shall bear interest at the Adjusted Term SOFR Rate for the Interest Period in effect for such Borrowing plus the Applicable Rate.

(c) Each RFR Loan shall bear interest at a rate per annum equal to the Adjusted Daily Simple SOFR plus the Applicable Rate.

(d) Notwithstanding the foregoing, if any principal of or interest on any Loan or any fee or other amount payable by the Borrower hereunder is not paid when due, whether at stated maturity, upon acceleration or otherwise, such overdue amount shall bear interest, after as well as before judgment, at a rate per annum equal to (i) in the case of overdue principal of any Loan, 2% plus the rate otherwise applicable to such Loan as provided in the preceding paragraphs of this Section or (ii) in the case of any other amount, 2% plus the rate applicable to ABR Loans as provided in paragraph (a) of this Section.

(e) Accrued interest on each Loan shall be payable in arrears on each Interest Payment Date for such Loan and, in the case of Revolving Loans, upon termination of the Commitments; provided that (i) interest accrued pursuant to paragraph (d) of this Section shall be payable on demand, (ii) in the event of any repayment or prepayment of any Loan (other than a prepayment of an ABR Revolving Loan prior to the end of the Availability Period), accrued interest on the principal amount repaid or prepaid shall be payable on the date of such repayment or prepayment and (iii) in the event of any conversion of any Term Benchmark Revolving Loan prior to the end of the current Interest Period therefor, accrued interest on such Loan shall be payable on the effective date of such conversion.

(f) All interest hereunder shall be computed on the basis of a year of 360 days, except that interest computed by reference to the Alternate Base Rate at times when the Alternate Base Rate is based on the Prime Rate shall be computed on the basis of a year of 365 days (or 366 days in a leap year), and in each case shall be payable for the actual number of days elapsed (including the first day but excluding the last day). The applicable Alternate Base Rate, Term SOFR Rate, Adjusted Daily Simple SOFR or Daily Simple SOFR shall be determined by the Administrative Agent, and such determination shall be conclusive absent manifest error.

SECTION 2.14 Alternate Rate of Interest.

(a) Subject to clauses (b) (c), (d), (e), and (f) of this Section 2.14, if:

(i) the Administrative Agent determines (which determination shall be conclusive and binding absent manifest error) (A) prior to the commencement of any Interest Period for a Term Benchmark Borrowing, that adequate and reasonable means do not exist for ascertaining the Adjusted Term SOFR Rate (including because the Term SOFR Reference Rate is not available or published on a current basis), for such Interest Period or (B) at any time, that adequate and reasonable means do not exist for ascertaining the applicable Adjusted Daily Simple SOFR; or

(ii) the Administrative Agent is advised by the Required Lenders that (A) prior to the commencement of any Interest Period for a Term Benchmark Borrowing, the Adjusted Term SOFR Rate for such Interest Period will not adequately and fairly reflect the cost to such Lenders of making or maintaining their Loans included in such Borrowing for such Interest Period or (B) at any time, Adjusted Daily Simple SOFR will not adequately and fairly reflect the cost to such Lenders of making or maintaining their Loans included in such Borrowing;

then the Administrative Agent shall give notice thereof to the Borrower and the Lenders by telephone, telecopy or electronic mail as promptly as practicable thereafter and, until (x) the Administrative Agent notifies the Borrower and the Lenders that the circumstances giving rise to such notice no longer exist with respect to the relevant Benchmark and (y) the Borrower delivers a new Interest Election Request in accordance with the terms of Section 2.08 or a new Borrowing Request in accordance with the terms of Section 2.03, (1) any Interest Election Request that requests the conversion of any Borrowing to, or continuation of any Borrowing as, a Term Benchmark Borrowing and any Borrowing Request that requests a Term Benchmark Borrowing, such Borrowing shall instead be deemed to be an Interest

Election Request or a Borrowing Request, as applicable, for (x) an RFR Borrowing so long as the Adjusted Daily Simple SOFR is not also the subject of Section 2.14(a)(i) or (ii) above or (y) an ABR Borrowing if the Adjusted Daily Simple SOFR also is the subject of Section 2.14(a)(i) or (ii) above and (2) any Borrowing Request that requests an RFR Borrowing shall instead be deemed to be a Borrowing Request, as applicable, for an ABR Borrowing if the Adjusted Daily Simple SOFR also is the subject of Section 2.14(a)(i) or (ii) above; provided that if the circumstances giving rise to such notice affect only one Type of Borrowings, then all other Types of Borrowings shall be permitted. Furthermore, if any Term Benchmark Loan or RFR Loan is outstanding on the date of the Borrower's receipt of the notice from the Administrative Agent referred to in this Section 2.14(a) with respect to a Relevant Rate applicable to such Term Benchmark Loan or RFR Loan, then until (x) the Administrative Agent notifies the Borrower and the Lenders that the circumstances giving rise to such notice no longer exist, with respect to the relevant Benchmark and (y) the Borrower delivers a new Interest Election Request in accordance with the terms of Section 2.03, (1) any Term Benchmark Loan shall on the last day of the Interest Period applicable to such Loan be converted by the Administrative Agent to, and shall constitute, (x) an RFR Borrowing so long as the Adjusted Daily Simple SOFR is not also the subject of Section 2.14(a)(i) or (ii) above or (y) an ABR Loan if the Adjusted Daily Simple SOFR also is the subject of Section 2.14(a)(i) or (ii) above, on such day, and (2) any such RFR Loan shall on and from such day be converted by the Administrative Agent to, and shall constitute an ABR Loan.

(b) Notwithstanding anything to the contrary herein or in any other Loan Document (and any Swap Agreement shall be deemed not to be a "Loan Document" for purposes of this Section 2.14), if a Benchmark Transition Event and its related Benchmark Replacement Date have occurred prior to the Reference Time in respect of any setting of the then-current Benchmark, then (x) if a Benchmark Replacement is determined in accordance with clause (1) of the definition of "Benchmark Replacement" for such Benchmark Replacement Date, such Benchmark Replacement will replace such Benchmark for all purposes hereunder and under any Loan Document in respect of such Benchmark setting and subsequent Benchmark settings without any amendment to, or further action or consent of any other party to, this Agreement or any other Loan Document and (y) if a Benchmark Replacement is determined in accordance with clause (2) of the definition of "Benchmark Replacement" for such Benchmark Replacement Date, such Benchmark Replacement will replace such Benchmark for all purposes hereunder and under any Loan Document in respect of any Benchmark setting at or after 5:00 p.m. (New York City time) on the fifth (5th) Business Day after the date notice of such Benchmark Replacement is provided to the Lenders without any amendment to, or further action or consent of any other party to, this Agreement or any other Loan Document so long as the Administrative Agent has not received, by such time, written notice of objection to such Benchmark Replacement from Lenders comprising the Required Lenders.

(c) Notwithstanding anything to the contrary herein or in any other Loan Document, the Administrative Agent will have the right to make Benchmark Replacement Conforming Changes from time to time and, notwithstanding anything to the contrary herein or in any other Loan Document, any amendments implementing such Benchmark Replacement Conforming Changes will become effective without any further action or consent of any other party to this Agreement or any other Loan Document.

(d) The Administrative Agent will promptly notify the Borrower and the Lenders of (i) any occurrence of a Benchmark Transition Event (ii) the implementation of any Benchmark Replacement, (iii) the effectiveness of any Benchmark Replacement Conforming Changes, (iv) the removal or reinstatement of any tenor of a Benchmark pursuant to clause (e) below and (v) the commencement or conclusion of any Benchmark Unavailability Period. Any determination, decision or election that may be made by the Administrative Agent or, if applicable, any Lender (or group of Lenders) pursuant to this Section 2.14, including any determination with respect to a tenor, rate or adjustment or of the occurrence or non-occurrence of an event, circumstance or date and any decision to take or refrain from taking any action or any selection, will be conclusive and binding absent manifest error and may be made in its or their sole discretion and without consent from any other party to this Agreement or any other Loan Document, except, in each case, as expressly required pursuant to this Section 2.14.

(e) Notwithstanding anything to the contrary herein or in any other Loan Document, at any time (including in connection with the implementation of a Benchmark Replacement), (i) if the then-current Benchmark is a term rate (including the Term SOFR Rate) and either (A) any tenor for such Benchmark is not displayed on a screen or other information service that publishes such rate from time to time as selected by the Administrative Agent in its reasonable discretion or (B) the regulatory supervisor for the administrator of such Benchmark has provided a public statement or publication of information announcing that any tenor for such Benchmark is or will be no longer representative, then the Administrative Agent may modify the definition of "Interest Period" for any Benchmark settings at or after such time to remove such unavailable or non-representative tenor and (ii) if a tenor that was removed pursuant to clause (i) above either (A) is subsequently displayed on a screen or information service for a Benchmark (including a Benchmark Replacement) or (B) is not, or is no longer, subject to an announcement that it is or will no longer be representative for a Benchmark (including a Benchmark Replacement), then the Administrative Agent may modify the definition of "Interest Period" for all Benchmark settings at or after such time to reinstate such previously removed tenor.

(f) Upon the Borrower's receipt of notice of the commencement of a Benchmark Unavailability Period, the Borrower may revoke any request for a Term Benchmark Borrowing or RFR Borrowing of, conversion to or continuation of Term Benchmark Loans or RFR Loans to be made, converted or continued during any Benchmark Unavailability Period and, failing that, the Borrower will be deemed to have converted any such request for a Term Benchmark Borrowing into a request for a Borrowing of or conversion to (A) an RFR Borrowing so long as the Adjusted Daily Simple SOFR is not the subject of a Benchmark Transition Event or (B) an ABR Borrowing if the Adjusted Daily Simple SOFR is the subject of a Benchmark Transition Event. During any Benchmark Unavailability Period or at any time that a tenor for the then-current Benchmark is not an Available Tenor, the component of ABR based upon the then-current Benchmark or such tenor for such Benchmark, as applicable, will not be used in any determination of ABR. Furthermore, if any Term Benchmark Loan or RFR Loan is outstanding on the date of the Borrower's receipt of notice of the commencement of a Benchmark Unavailability Period with respect to a Relevant Rate applicable to such Term Benchmark Loan or RFR Loan, then until such time as a Benchmark Replacement is implemented pursuant to this Section 2.14, (1) any Term Benchmark Loan shall on the last day of the Interest Period applicable to such Loan, be converted by the Administrative Agent to, and shall constitute, (x) an RFR Borrowing so long as the Adjusted Daily Simple SOFR is not the subject of a Benchmark Transition Event or (y) an ABR Loan if the Adjusted Daily Simple SOFR is the subject of a Benchmark Transition Event, on such date and (2) any such RFR Loan shall on and from such day, be converted by the Administrative Agent to, and shall constitute an ABR Loan.

SECTION 2.15 Increased Costs. (a) If any Change in Law shall:

(i) impose, modify or deem applicable any reserve, special deposit, liquidity or similar requirement (including any compulsory loan requirement, insurance charge or other assessment) against assets of, deposits with or for the account of, or credit extended by, any Lender or any Issuing Bank;

(ii) impose on any Lender or any Issuing Bank or the applicable offshore interbank market any other condition, cost or expense (other than Taxes) affecting this Agreement or Loans made by such Lender or any Letter of Credit or participation therein; or

(iii) subject any Recipient to any Taxes (other than (A) Indemnified Taxes, (B) Taxes described in clauses (b) through (d) of the definition of Excluded Taxes and (C) Connection Income Taxes) on its loans, loan principal, letters of credit, commitments, or other obligations, or its deposits, reserves, other liabilities or capital attributable thereto;

and the result of any of the foregoing shall be to increase the cost to such Lender or such other Recipient of making, continuing, converting into or maintaining any Loan or of maintaining its obligation to make any such Loan or to increase the cost to such Lender, such Issuing Bank or such other Recipient of participating in, issuing or maintaining any Letter of Credit or to reduce the amount of any sum received or receivable by such Lender, such Issuing Bank or such other Recipient hereunder, whether of principal, interest or otherwise, then the Borrower will pay to such Lender, such Issuing Bank or such other Recipient, as the case may be, such additional amount or amounts as will compensate such Lender, such

Issuing Bank or such other Recipient, as the case may be, for such additional costs incurred or reduction suffered.

(b) If any Lender or any Issuing Bank determines that any Change in Law regarding capital or liquidity requirements has or would have the effect of reducing the rate of return on such Lender's or such Issuing Bank's capital or on the capital of such Lender's or such Issuing Bank's holding company, if any, as a consequence of this Agreement or the Loans made by, or participations in Letters of Credit held by, such Lender, or the Letters of Credit issued by such Issuing Bank, to a level below that which such Lender or such Issuing Bank or such Lender's or such Issuing Bank's holding company could have achieved but for such Change in Law (taking into consideration such Lender's or such Issuing Bank's policies and the policies of such Lender's or such Issuing Bank's holding company with respect to capital adequacy and liquidity), then from time to time the Borrower will pay to such Lender or such Issuing Bank, as the case may be, such additional amount or amounts as will compensate such Lender or such Issuing Bank or such Lender's or such Issuing Bank's holding company for any such reduction suffered.

(c) A certificate of a Lender or an Issuing Bank setting forth the amount or amounts necessary to compensate such Lender or such Issuing Bank or its holding company, as the case may be, as specified in paragraph (a) or (b) of this Section shall be delivered to the Borrower and shall be conclusive absent manifest error. The Borrower shall pay such Lender or such Issuing Bank, as the case may be, the amount shown as due on any such certificate within ten (10) days after receipt thereof.

(d) Failure or delay on the part of any Lender or any Issuing Bank to demand compensation pursuant to this Section shall not constitute a waiver of such Lender's or such Issuing Bank's right to demand such compensation; provided that the Borrower shall not be required to compensate a Lender or an Issuing Bank pursuant to this Section for any increased costs or reductions incurred more than 270 days prior to the date that such Lender or such Issuing Bank, as the case may be, notifies the Borrower of the Change in Law giving rise to such increased costs or reductions and of such Lender's or such Issuing Bank's intention to claim compensation therefor; provided further that, if the Change in Law giving rise to such increased costs or reductions is retroactive, then the 270-day period referred to above shall be extended to include the period of retroactive effect thereof.

SECTION 2.16 Break Funding Payments. With respect to Loans that are not RFR Loans, in the event of (i) the payment of any principal of any Term Benchmark Loan other than on the last day of an Interest Period applicable thereto (including as a result of an Event of Default or an optional prepayment of Loans pursuant to Section 2.11), (ii) the conversion of any Term Benchmark Loan other than on the last day of the Interest Period applicable thereto, (iii) the failure to borrow, convert, continue or prepay any Term Benchmark Loan on the date specified in any notice delivered pursuant hereto (regardless of whether such notice may be revoked under Section 2.11 and is revoked in accordance therewith) or (iv) the assignment of any Term Benchmark Loan other than on the last day of the Interest Period applicable thereto as a result of a request by the Borrower pursuant to Section 2.19, then, in any such event, the Borrower shall compensate each Lender for the loss, cost and expense attributable to such event. A certificate of any Lender setting forth any amount or amounts that such Lender is entitled to receive pursuant to this Section shall be delivered to the Borrower and shall be conclusive absent manifest error. The Borrower shall pay such Lender the amount shown as due on any such certificate within ten (10) days after receipt thereof.

SECTION 2.17 Withholding of Taxes; Gross-Up. (a) Payments Free of Taxes. Any and all payments by or on account of any obligation of the Borrower under any Loan Document shall be made without deduction or withholding for any Taxes, except as required by applicable law. If any applicable law (as determined in the good faith discretion of an applicable withholding agent) requires the deduction or withholding of any Tax from any such payment by a withholding agent, then the applicable withholding agent shall be entitled to make such deduction or withholding and shall timely pay the full amount deducted or withheld to the relevant Governmental Authority in accordance with applicable law and, if such Tax is an Indemnified Tax, then the sum payable by the Borrower shall be increased as necessary so that after such deduction or withholding has been made (including such deductions and withholdings applicable to additional sums payable under this Section 2.17) the applicable Recipient receives an amount equal to the sum it would have received had no such deduction or withholding been made.

(b) Payment of Other Taxes by the Borrower. The Borrower shall timely pay to the relevant Governmental Authority in accordance with applicable law, or at the option of the Administrative Agent timely reimburse it for, Other Taxes.

(c) Evidence of Payments. As soon as practicable after any payment of Taxes by the Borrower to a Governmental Authority pursuant to this Section 2.17, the Borrower shall deliver to the Administrative Agent the original or a certified copy of a receipt issued by such Governmental Authority evidencing such payment, a copy of the return reporting such payment or other evidence of such payment reasonably satisfactory to the Administrative Agent.

(d) Indemnification by the Borrower. The Borrower shall indemnify each Recipient, within 10 days after demand therefor, for the full amount of any Indemnified Taxes (including Indemnified Taxes imposed or asserted on or attributable to amounts payable under this Section) payable or paid by such Recipient or required to be withheld or deducted from a payment to such Recipient and any reasonable expenses arising therefrom or with respect thereto, whether or not such Indemnified Taxes were correctly or legally imposed or asserted by the relevant Governmental Authority. A certificate as to the amount of such payment or liability delivered to the Borrower by a Lender (with a copy to the Administrative Agent), or by the Administrative Agent on its own behalf or on behalf of a Lender, shall be conclusive absent manifest error.

(e) Indemnification by the Lenders. Each Lender shall severally indemnify the Administrative Agent, within 10 days after demand therefor, for (i) any Indemnified Taxes attributable to such Lender (but only to the extent that the Borrower has not already indemnified the Administrative Agent for such Indemnified Taxes and without limiting the obligation of the Borrower to do so), (ii) any Taxes attributable to such Lender's failure to comply with the provisions of Section 9.04(c) relating to the maintenance of a Participant Register and (iii) any Excluded Taxes attributable to such Lender, in each case, that are payable or paid by the Administrative Agent in connection with any Loan Document, and any reasonable expenses arising therefrom or with respect thereto, whether or not such Taxes were correctly or legally imposed or asserted by the relevant Governmental Authority. A certificate as to the amount of such payment or liability delivered to any Lender by the Administrative Agent shall be conclusive absent manifest error. Each Lender hereby authorizes the Administrative Agent to set off and apply any and all amounts at any time owing to such Lender under any Loan Document or otherwise payable by the Administrative Agent to the Lender from any other source against any amount due to the Administrative Agent under this paragraph (e).

(f) Status of Lenders. (i) Any Lender that is entitled to an exemption from or reduction of withholding Tax with respect to payments made under any Loan Document shall deliver to the Borrower and the Administrative Agent, at the time or times reasonably requested by the Borrower or the Administrative Agent, such properly completed and executed documentation reasonably requested by the Borrower or the Administrative Agent as will permit such payments to be made without withholding or at a reduced rate of withholding. In addition, any Lender, if reasonably requested by the Borrower or the Administrative Agent, shall deliver such other documentation prescribed by applicable law or reasonably requested by the Borrower or the Administrative Agent as will enable the Borrower or the Administrative Agent to determine whether or not such Lender is subject to backup withholding or information reporting requirements. Notwithstanding anything to the contrary in the preceding two sentences, the completion, execution and submission of such documentation (other than such documentation set forth in Section 2.17(f)(ii)(A), (ii)(B) and (ii)(D) below) shall not be required if in the Lender's reasonable judgment such completion, execution or submission would subject such Lender to any material unreimbursed cost or expense or would materially prejudice the legal or commercial position of such Lender.

(ii) Without limiting the generality of the foregoing, in the event that the Borrower is a U.S. Person:

(A) any Lender that is a U.S. Person shall deliver to the Borrower and the Administrative Agent on or prior to the date on which such Lender becomes a Lender under this Agreement (and from time to time thereafter upon the reasonable request of the Borrower or the Administrative Agent), an executed copy of IRS Form W-9 certifying that such Lender is exempt from U.S. federal backup withholding tax;

(B) any Foreign Lender shall, to the extent it is legally entitled to do so, deliver to the Borrower and the Administrative Agent (in such number of copies as shall be requested by the recipient) on or prior to the date on which such Foreign Lender becomes a Lender under this Agreement (and from time to time thereafter upon the reasonable request of the Borrower or the Administrative Agent), whichever of the following is applicable:

(1) in the case of a Foreign Lender claiming the benefits of an income tax treaty to which the United States is a party (x) with respect to payments of interest under any Loan Document, an executed copy of IRS Form W-8BEN-E or IRS Form W-8BEN establishing an exemption from, or reduction of, U.S. federal withholding Tax pursuant to the "interest" article of such tax treaty and (y) with respect to any other applicable payments under any Loan Document, IRS Form W-8BEN-E or IRS Form W-8BEN establishing an exemption from, or reduction of, U.S. Federal withholding Tax pursuant to the "business profits" or "other income" article of such tax treaty;

(2) in the case of a Foreign Lender claiming that its extension of credit will generate U.S. effectively connected income, an executed copy of IRS Form W-8ECI;

(3) in the case of a Foreign Lender claiming the benefits of the exemption for portfolio interest under Section 881(c) of the Code, (x) a certificate substantially in the form of Exhibit E-1 to the effect that such Foreign Lender is not a "bank" within the meaning of Section 881(c)(3)(A) of the Code, a "10 percent shareholder" of the Borrower within the meaning of Section 881(c)(3)(B) of the Code, or a "controlled foreign corporation" described in Section 881(c)(3)(C) of the Code (a "U.S. Tax Compliance Certificate") and (y) an executed copy of IRS Form W-8BEN-E or IRS Form W-8BEN; or

(4) to the extent a Foreign Lender is not the beneficial owner, an executed copy of IRS Form W-8IMY, accompanied by IRS Form W-8ECI, IRS Form W-8BEN-E or IRS Form W-8BEN, a U.S. Tax Compliance Certificate substantially in the form of Exhibit E-2 or Exhibit E-3, IRS Form W-9, and/or other certification documents from each beneficial owner, as applicable; provided that if the Foreign Lender is a partnership and one or more direct or indirect partners of such Foreign Lender are claiming the portfolio interest exemption, such Foreign Lender may provide a U.S. Tax Compliance Certificate substantially in the form of Exhibit E-4 on behalf of each such direct and indirect partner;

(C) any Foreign Lender shall, to the extent it is legally entitled to do so, deliver to the Borrower and the Administrative Agent (in such number of copies as shall be requested by the recipient) on or prior to the date on which such Foreign Lender becomes a Lender under this Agreement (and from time to time thereafter upon the reasonable request of the Borrower or the Administrative Agent), executed copies of any other form prescribed by applicable law as a basis for claiming exemption from or a reduction in U.S. Federal withholding Tax, duly completed, together with such supplementary documentation as may be prescribed by applicable law to permit the Borrower or the Administrative Agent to determine the withholding or deduction required to be made; and

(D) if a payment made to a Lender under any Loan Document would be subject to U.S. federal withholding Tax imposed by FATCA if such Lender were to fail to comply with the applicable reporting requirements of FATCA (including those contained in Section 1471(b) or 1472(b) of the Code, as applicable), such Lender shall deliver to the Borrower and the Administrative Agent at the time or times prescribed by law and at such time or times reasonably requested by the Borrower or the Administrative Agent such documentation prescribed by applicable law (including as prescribed by Section 1471(b)(3)(C)(i) of the Code) and such additional documentation reasonably requested by the Borrower or the Administrative Agent as may be necessary for the Borrower and the Administrative Agent to comply with their obligations under FATCA and to determine that such Lender has complied with such Lender's obligations under FATCA or to determine the amount to deduct and withhold from such payment. Solely for purposes of this clause (D), "FATCA" shall include any amendments made to FATCA after the date of this Agreement.

Each Lender agrees that if any form or certification it previously delivered expires or becomes obsolete or inaccurate in any respect, it shall update such form or certification or promptly notify the Borrower and the Administrative Agent in writing of its legal inability to do so.

(g) Treatment of Certain Refunds. If any party determines, in its sole discretion exercised in good faith, that it has received a refund of any Taxes as to which it has been indemnified pursuant to this Section 2.17 (including by the payment of additional amounts pursuant to this Section 2.17), it shall pay to the indemnifying party an amount equal to such refund (but only to the extent of indemnity payments made under this Section 2.17 with respect to the Taxes giving rise to such refund), net of all out-of-pocket expenses (including Taxes) of such indemnified party and without interest (other than any interest paid by the relevant Governmental Authority with respect to such refund). Such indemnifying party, upon the request of such indemnified party, shall repay to such indemnified party the amount paid over pursuant to this paragraph (g) (plus any penalties, interest or other charges imposed by the relevant Governmental Authority) in the event that such indemnified party is required to repay such refund to such Governmental Authority. Notwithstanding anything to the contrary in this paragraph (g), in no event will the indemnified party be required to pay any amount to an indemnifying party pursuant to this paragraph (g) the payment of which would place the indemnified party in a less favorable net after-Tax position than the indemnified party would have been in if the Tax subject to indemnification and giving rise to such refund had not been deducted, withheld or otherwise imposed and the indemnification payments or additional amounts with respect to such Tax had never been paid. This paragraph shall not be construed to require any indemnified party to make available its Tax returns (or any other information relating to its Taxes that it deems confidential) to the indemnifying party or any other Person.

(h) Survival. Each party's obligations under this Section 2.17 shall survive the resignation or replacement of the Administrative Agent or any assignment of rights by, or the replacement of, a Lender, the termination of the Commitments and the repayment, satisfaction or discharge of all obligations under any Loan Document.

(i) Defined Terms. For purposes of this Section 2.17, the term "Lender" includes the Issuing Banks and the term "applicable law" includes FATCA.

SECTION 2.18 Payments Generally; Pro Rata Treatment; Sharing of Set-offs. (a) The Borrower shall make each payment required to be made by it hereunder (whether of principal, interest, fees or reimbursement of LC Disbursements, or of amounts payable under Section 2.15, 2.16 or 2.17, or otherwise) prior to 12:00 noon, New York City time on the date when due, in immediately available funds, without set-off, recoupment or counterclaim. Any amounts received after such time on any date may, in the discretion of the Administrative Agent, be deemed to have been received on the next succeeding Business Day for purposes of calculating interest thereon. All such payments shall be made to the Administrative Agent at its offices as specified in Section 9.01(a)(ii), except payments to be made directly to an Issuing Bank as expressly provided herein and except that payments pursuant to Sections 2.15, 2.16, 2.17 and 9.03 shall be made directly to the Persons entitled thereto. The Administrative Agent shall distribute any such payments received by it for the account of any other

Person to the appropriate recipient promptly following receipt thereof. If any payment hereunder shall be due on a day that is not a Business Day, the date for payment shall be extended to the next succeeding Business Day, and, in the case of any payment accruing interest, interest thereon shall be payable for the period of such extension. All payments hereunder shall be made in Dollars.

(b) If at any time insufficient funds are received by and available to the Administrative Agent to pay fully all amounts of principal, unreimbursed LC Disbursements, interest and fees then due hereunder, such funds shall be applied (i) first, towards payment of interest and fees then due hereunder, ratably among the parties entitled thereto in accordance with the amounts of interest and fees then due to such parties, and (ii) second, towards payment of principal and unreimbursed LC Disbursements then due hereunder, ratably among the parties entitled thereto in accordance with the amounts of principal and unreimbursed LC Disbursements then due to such parties.

(c) If any Lender shall, by exercising any right of set-off or counterclaim or otherwise, obtain payment in respect of any principal of or interest on any of its Revolving Loans or participations in LC Disbursements resulting in such Lender receiving payment of a greater proportion of the aggregate amount of its Revolving Loans and participations in LC Disbursements and accrued interest thereon than the proportion received by any other Lender, then the Lender receiving such greater proportion shall purchase (for cash at face value) participations in the Revolving Loans and participations in LC Disbursements of other Lenders to the extent necessary so that the benefit of all such payments shall be shared by the Lenders ratably in accordance with the aggregate amount of principal of and accrued interest on their respective Revolving Loans and participations in LC Disbursements; provided that (i) if any such participations are purchased and all or any portion of the payment giving rise thereto is recovered, such participations shall be rescinded and the purchase price restored to the extent of such recovery, without interest, and (ii) the provisions of this paragraph shall not be construed to apply to any payment made by the Borrower pursuant to and in accordance with the express terms of this Agreement or any payment obtained by a Lender as consideration for the assignment of or sale of a participation in any of its Loans or participations in LC Disbursements to any assignee or participant, other than to the Borrower or any Subsidiary or Affiliate thereof (as to which the provisions of this paragraph shall apply). The Borrower consents to the foregoing and agrees, to the extent it may effectively do so under applicable law, that any Lender acquiring a participation pursuant to the foregoing arrangements may exercise against the Borrower rights of set-off and counterclaim with respect to such participation as fully as if such Lender were a direct creditor of the Borrower in the amount of such participation.

(d) Unless the Administrative Agent shall have received notice from the Borrower prior to the date on which any payment is due to the Administrative Agent for the account of the Lenders or the Issuing Banks hereunder that the Borrower will not make such payment, the Administrative Agent may assume that the Borrower has made such payment on such date in accordance herewith and may, in reliance upon such assumption, distribute to the Lenders or the Issuing Banks, as the case may be, the amount due. In such event, if the Borrower has not in fact made such payment, then each of the Lenders or the Issuing Banks, as the case may be, severally agrees to repay to the Administrative Agent forthwith on demand the amount so distributed to such Lender or such Issuing Bank with interest thereon, for each day from and including the date such amount is distributed to it to but excluding the date of payment to the Administrative Agent, at the NYFRB Rate.

SECTION 2.19 Mitigation Obligations; Replacement of Lenders. (a) If any Lender requests compensation under Section 2.15, or the Borrower is required to pay any Indemnified Taxes or additional amounts to any Lender or any Governmental Authority for the account of any Lender pursuant to Section 2.17, then such Lender shall use reasonable efforts to designate a different lending office for funding or booking its Loans hereunder or to assign its rights and obligations hereunder to another of its offices, branches or Affiliates, if, in the judgment of such Lender, such designation or assignment (i) would eliminate or reduce amounts payable pursuant to Section 2.15 or 2.17, as the case may be, in the future and (ii) would not subject such Lender to any unreimbursed cost or expense and would not otherwise be disadvantageous to such Lender. The Borrower hereby agrees to pay all reasonable costs and expenses incurred by any Lender in connection with any such designation or assignment.

(b) If any Lender requests compensation under Section 2.15, or if the Borrower is required to pay any Indemnified Taxes or additional amounts to any Lender or any Governmental

Authority for the account of any Lender pursuant to Section 2.17, or if any Lender becomes a Defaulting Lender, or if any Lender does not consent to any proposed amendment, supplement, modification, consent or waiver of any provision of this Agreement or any other Loan Document that requires the consent of each of the Lenders or each of the Lenders affected thereby (so long as the consent of the Required Lenders (with the percentage in such definition being deemed to be 50% for this purpose) has been obtained), then the Borrower may, at its sole expense and effort, upon notice to such Lender and the Administrative Agent, require such Lender to assign and delegate, without recourse (in accordance with and subject to the restrictions contained in Section 9.04), all its interests, rights (other than its existing rights to payments pursuant to Sections 2.15 or 2.17) and obligations under this Agreement and the other Loan Documents to an assignee that shall assume such obligations (which assignee may be another Lender, if a Lender accepts such assignment); provided that (i) the Borrower shall have received the prior written consent of the Administrative Agent (and if a Commitment is being assigned, the Issuing Banks), which consent shall not unreasonably be withheld, (ii) such Lender shall have received payment of an amount equal to the outstanding principal of its Loans and participations in LC Disbursements, accrued interest thereon, accrued fees and all other amounts payable to it hereunder, from the assignee (to the extent of such outstanding principal and accrued interest and fees) or the Borrower (in the case of all other amounts) and (iii) in the case of any such assignment resulting from a claim for compensation under Section 2.15 or payments required to be made pursuant to Section 2.17, such assignment will result in a reduction in such compensation or payments. A Lender shall not be required to make any such assignment and delegation if, prior thereto, as a result of a waiver by such Lender or otherwise, the circumstances entitling the Borrower to require such assignment and delegation cease to apply. Each party hereto agrees that (a) an assignment required pursuant to this paragraph may be effected pursuant to an Assignment and Assumption executed by the Borrower, the Administrative Agent and the assignee (or, to the extent applicable, an agreement incorporating an Assignment and Assumption by reference pursuant to an Approved Electronic Platform as to which the Administrative Agent and such parties are participants), and (b) the Lender required to make such assignment need not be a party thereto in order for such assignment to be effective and shall be deemed to have consented to an be bound by the terms thereof; provided that, following the effectiveness of any such assignment, the other parties to such assignment agree to execute and deliver such documents necessary to evidence such assignment as reasonably requested by the applicable Lender, provided that any such documents shall be without recourse to or warranty by the parties thereto.

SECTION 2.20 Expansion Option. The Borrower may from time to time elect to increase the Commitments or enter into one or more tranches of term loans (each an "Incremental Term Loan"), in each case a minimum amount of $10,000,000 and any integral of $5,000,000 in excess thereof, so long as, after giving effect thereto, the aggregate amount of such increases and all such Incremental Term Loans does not exceed $100,000,000. The Borrower may arrange for any such increase or tranche to be provided by one or more Lenders (each Lender so agreeing to an increase in its Commitment, or to participate in such Incremental Term Loans, an "Increasing Lender"), or by one or more new banks, financial institutions or other entities (each such new bank, financial institution or other entity, an "Augmenting Lender"; provided that no Ineligible Institution may be an Augmenting Lender), which agree to increase their existing Commitments, or to participate in such Incremental Term Loans, or provide new Commitments, as the case may be; provided that (i) each Augmenting Lender, shall be subject to the approval of the Borrower, the Administrative Agent and the Issuing Banks to the extent the consent of the Issuing Banks would be required to effect an assignment under Section 9.04(b), and (ii) (x) in the case of an Increasing Lender, the Borrower and such Increasing Lender execute an agreement substantially in the form of Exhibit B hereto, and (y) in the case of an Augmenting Lender, the Borrower and such Augmenting Lender execute an agreement substantially in the form of Exhibit C hereto. No consent of any Lender (other than the Lenders participating in the increase or any Incremental Term Loan) shall be required for any increase in Commitments or Incremental Term Loan pursuant to this Section 2.20. Increases and new Commitments and Incremental Term Loans created pursuant to this Section 2.20 shall become effective on the date agreed by the Borrower, the Administrative Agent and the relevant Increasing Lenders or Augmenting Lenders, and the Administrative Agent shall notify each Lender thereof. Notwithstanding the foregoing, no increase in the Commitments (or in the Commitment of any Lender) or tranche of Incremental Term Loans shall become effective under this paragraph unless, (i) on the proposed date of the effectiveness of such increase or Incremental Term Loans, (A) the conditions set forth in paragraphs (a) and (b) of Section 4.02 shall be satisfied or waived by the Required Lenders and the Administrative Agent shall have received a certificate to that effect dated such date and executed by a Financial Officer of the Borrower and (B) the Borrower shall be in compliance (on a pro forma basis) with the covenants contained in Section 6.02 and (ii) the Administrative Agent shall have received documents and opinions consistent with those delivered on the Restatement Effective Date as to the organizational power and authority of the Borrower to borrow hereunder after giving effect to such increase. On the effective date of any increase in the Commitments or any Incremental Term Loans being made, (i) each relevant Increasing Lender and Augmenting Lender shall make available to the Administrative Agent such amounts in immediately available funds as the Administrative Agent shall determine, for the benefit of the other Lenders, as being required in order to cause, after giving effect to such increase and the use of such amounts to make payments to such other Lenders, each Lender's portion of the outstanding Revolving Loans of all the Lenders to equal its Applicable Percentage of such outstanding Revolving Loans, and (ii) except in the case of any Incremental Term Loans, the Borrower shall be deemed to have repaid and reborrowed all outstanding Revolving Loans as of the date of any increase in the Commitments (with such reborrowing to consist of the Types of Revolving Loans, with related Interest Periods if applicable, specified in a notice delivered by the Borrower, in accordance with the requirements of Section 2.03). The deemed payments made pursuant to clause (ii) of the immediately preceding sentence shall be accompanied by payment of all accrued interest on the amount prepaid and, in respect of each Term Benchmark Loan, shall be subject to indemnification by the Borrower pursuant to the provisions of Section 2.16 if the deemed payment occurs other than on the last day of the related Interest Periods. The Incremental Term Loans (a) shall rank pari passu in right of payment with the Revolving Loans, (b) shall not mature earlier than the Maturity Date (but may have amortization prior to such date) and (c) shall be treated substantially the same as (and in any event no more favorably than) the Revolving Loans; provided that (i) the terms and conditions applicable to any tranche of Incremental Term Loans maturing after the Maturity Date may provide for material additional or different financial or other covenants or prepayment requirements applicable only during periods after the Maturity Date and (ii) the Incremental Term Loans may be priced differently than the Revolving Loans. Incremental Term Loans may be made hereunder pursuant to an amendment or restatement (an "Incremental Term Loan Amendment") of this Agreement and, as appropriate, the other Loan Documents, executed by the Borrower, each Increasing Lender participating in such tranche, each Augmenting Lender participating in such tranche, if any, and the Administrative Agent. The Incremental Term Loan Amendment may, without the consent of any other Lenders, effect such amendments to this Agreement and the other Loan Documents as may be necessary or appropriate, in the reasonable opinion of the Administrative Agent, to effect the provisions of this Section 2.20. Nothing contained in this Section 2.20 shall constitute, or otherwise be deemed to be, a commitment on the part of any Lender to increase its Commitment hereunder, or provide Incremental Term Loans, at any time. In connection with any increase of the Commitments or Incremental Term Loans pursuant to this Section 2.20, any Augmenting Lender becoming a party hereto shall (1) execute such documents and agreements as the Administrative Agent may reasonably request and (2) in the case of any Augmenting Lender that is organized under the laws of a jurisdiction outside of the United States of America, provide to the Administrative Agent, its name, address, tax identification number and/or such other information as shall be necessary for the Administrative Agent to comply with "know your customer" and anti-money laundering rules and regulations, including without limitation, the Patriot Act.

SECTION 2.21 Defaulting Lenders. Notwithstanding any provision of this Agreement to the contrary, if any Lender becomes a Defaulting Lender, then the following provisions shall apply for so long as such Lender is a Defaulting Lender:

(a) fees shall cease to accrue on the Commitment of such Defaulting Lender pursuant to Section 2.12(a);

(b) any payment of principal, interest, fees or other amounts received by the Administrative Agent for the account of such Defaulting Lender (whether voluntary or mandatory, at maturity, pursuant to Section 7.02 or otherwise) or received by the Administrative Agent from a Defaulting Lender pursuant to Section 9.08 shall be applied at such time or times as may be determined by the Administrative Agent as follows: *first*, to the payment of any amounts owing by such Defaulting Lender to the Administrative Agent hereunder; *second*, to the payment on a pro rata basis of any amounts owing by such Defaulting Lender to any Issuing Bank hereunder; *third*, to cash collateralize the LC Exposure with respect to such Defaulting Lender in accordance with this Section; *fourth*, as the Borrower may request (so long as no Default or Event of Default exists), to the funding of any Loan in respect of which such Defaulting Lender has failed to fund its portion thereof as required by this Agreement, as determined by the Administrative Agent; *fifth*, if so determined by the Administrative Agent and the Borrower, to be held in a deposit account and released pro rata in order to (x) satisfy such Defaulting Lender's potential future funding obligations with respect to Loans under this Agreement and (y) cash collateralize future LC Exposure with respect to such Defaulting Lender with respect to future Letters of Credit issued under this Agreement, in accordance with this Section; *sixth*, to the payment of any amounts owing to the Lenders or the Issuing Banks as a result of any judgment of a court of competent jurisdiction obtained by any Lender or the Issuing Banks against such Defaulting Lender as a result of such Defaulting Lender's breach of its obligations under this Agreement or under any other Loan Document; *seventh*, so long as no Default or Event of Default exists, to the payment of any amounts owing to the Borrower as a result of any judgment of a court of competent jurisdiction obtained by the Borrower against such Defaulting Lender as a result of such Defaulting Lender's breach of its obligations under this Agreement or under any other Loan Document; and *eighth*, to such Defaulting Lender or as otherwise directed by a court of competent jurisdiction; provided that if (x) such payment is a payment of the principal amount of any Loans or LC Disbursements in respect of which such Defaulting Lender has not fully funded its appropriate share, and (y) such Loans were made or the related Letters of Credit were issued at a time when the conditions set forth in Section 4.02 were satisfied or waived, such payment shall be applied solely to pay the Loans of, and LC Disbursements owed to, all non-Defaulting Lenders on a pro rata basis prior to being applied to the payment of any Loans of, or LC Disbursements owed to, such Defaulting Lender until such time as all Loans and funded and unfunded participations in the Borrower's obligations corresponding to such Defaulting Lender's LC Exposure are held by the Lenders pro rata in accordance with the Commitments without giving effect to clause (d) below. Any payments, prepayments or other amounts paid or payable to a Defaulting Lender that are applied (or held) to pay amounts owed by a Defaulting Lender or to post cash collateral pursuant to this Section shall be deemed paid to and redirected by such Defaulting Lender, and each Lender irrevocably consents hereto;

(c) the Commitment and Revolving Credit Exposure of such Defaulting Lender shall not be included in determining whether the Required Lenders have taken or may take any action hereunder (including any consent to any amendment, waiver or other modification pursuant to Section 9.02); provided, that, except as otherwise provided in Section 9.02, this clause (c) shall not apply to the vote of a Defaulting Lender in the case of an amendment, waiver or other modification requiring the consent of such Lender or each Lender directly affected thereby;

(d) if any LC Exposure exists at the time such Lender becomes a Defaulting Lender then:

(i) all or any part of the LC Exposure of such Defaulting Lender shall be reallocated among the non-Defaulting Lenders in accordance with their respective Applicable Percentages but only to the extent that such reallocation does not, as to any non-Defaulting Lender, cause such non-Defaulting Lender's Revolving Credit Exposure to exceed its Commitment;

(ii) if the reallocation described in clause (i) above cannot, or can only partially, be effected, the Borrower shall within three (3) Business Days following notice by the Administrative Agent, cash collateralize for the benefit of the applicable Issuing Banks only the Borrower's obligations corresponding to such Defaulting Lender's LC Exposure (after giving effect to any partial reallocation pursuant to clause (i) above) in accordance with the procedures set forth in Section 2.06(j) for so long as such LC Exposure is outstanding;

(iii) if the Borrower cash collateralizes any portion of such Defaulting Lender's LC Exposure pursuant to clause (ii) above, the Borrower shall not be required to pay any fees to such Defaulting Lender pursuant to Section 2.12(b) with respect to such Defaulting Lender's LC Exposure during the period such Defaulting Lender's LC Exposure is cash collateralized;

(iv) if the LC Exposure of the non-Defaulting Lenders is reallocated pursuant to clause (i) above, then the fees payable to the Lenders pursuant to Section 2.12(b) shall be adjusted in accordance with such non-Defaulting Lenders' Applicable Percentages; and

(v) if all or any portion of such Defaulting Lender's LC Exposure is neither reallocated nor cash collateralized pursuant to clause (i) or (ii) above, then, without prejudice to any rights or remedies of any Issuing Bank or any other Lender hereunder, all facility fees that otherwise would have been payable to such Defaulting Lender (solely with respect to the portion of such Defaulting Lender's Commitment that was utilized by such LC Exposure) and letter of credit fees payable under Section 2.12(b) with respect to such Defaulting Lender's LC Exposure shall be payable to the Issuing Banks until and to the extent that such LC Exposure is reallocated and/or cash collateralized; and

(e) so long as such Lender is a Defaulting Lender, no Issuing Bank shall be required to issue, amend or increase any Letter of Credit, unless it is satisfied that the related exposure and the Defaulting Lender's then outstanding LC Exposure will be 100% covered by the Commitments of the non-Defaulting Lenders and/or cash collateral will be provided by the Borrower in accordance with Section 2.21(d), and LC Exposure related to any newly issued or increased Letter of Credit shall be allocated among non-Defaulting Lenders in a manner consistent with Section 2.21(d)(i) (and such Defaulting Lender shall not participate therein).

If (i) a Bankruptcy Event or a Bail-In Action with respect to a Lender Parent shall occur following the date hereof and for so long as such event shall continue or (ii) any Issuing Bank has a good faith belief that any Lender has defaulted in fulfilling its obligations under one or more other agreements in which such Lender commits to extend credit, no Issuing Bank shall be required to issue, amend or increase any Letter of Credit, unless the Issuing Banks, as the case may be, shall have entered into arrangements with the Borrower or such Lender, satisfactory to such Issuing Bank, as the case may be, to defease any risk to it in respect of such Lender hereunder.

In the event that the Administrative Agent, the Borrower and each Issuing Bank agrees that a Defaulting Lender has adequately remedied all matters that caused such Lender to be a Defaulting Lender, then the LC Exposure of the Lenders shall be readjusted to reflect the inclusion of such Lender's Commitment and on such date such Lender shall purchase at par such of the Loans of the other Lenders as the Administrative Agent shall determine may be necessary in order for such Lender to hold such Loans in accordance with its Applicable Percentage.

SECTION 2.22 Extension of Maturity Date.

(a) The Borrower may, by delivering an Extension Request to the Administrative Agent (who shall promptly deliver a copy to each of the Lenders), not less than 60 days in advance of the Maturity Date in effect at such time (the "Existing Maturity Date"), request that the Lenders extend the Existing Maturity Date to the first anniversary of such Existing Maturity Date (or, if such date is not a Business Day, the immediately preceding Business Day). Each Lender, acting in its sole discretion, shall, by written notice to the Administrative Agent given not later than the date that is the 20th day after the date of the Extension Request, or if such date is not a Business Day, the immediately following Business Day (the "Response Date"), advise the Administrative Agent in writing whether or not such Lender agrees to the requested extension. Each Lender that advises the Administrative Agent that it will not extend the Existing Maturity Date is referred to herein as a "Non-extending Lender"; provided, that any Lender that does not advise the Administrative Agent of its consent to such requested extension by the Response Date and any Lender that is a Defaulting Lender on the Response Date shall be deemed to be a Non-extending Lender. The Administrative Agent shall notify the Borrower, in writing, of the Lenders' elections promptly following the Response Date. The election of any Lender to agree to such an extension shall not obligate any other Lender to so agree, and it is understood that no Lender shall have any obligation whatsoever to agree to any request made by the Borrower for an extension of the Existing Maturity Date. The Maturity Date may be extended no more than two times pursuant to this Section 2.22.

(b) (i) If, by the Response Date, Lenders holding Commitments that aggregate 50% or more of the Aggregate Commitment shall constitute Non-extending Lenders, then the Existing Maturity Date shall not be extended and the outstanding principal balance of all Loans and other amounts payable hereunder shall be payable, and the Commitments shall terminate, on the Existing Maturity Date in effect prior to such extension.

(ii) If (and only if), by the Response Date, Lenders holding Commitments that aggregate more than 50% of the Aggregate Commitment shall have agreed to extend the Existing Maturity Date (each such consenting Lender, an "Extending Lender"), then effective as of the Existing Maturity Date, the Maturity Date for such Extending Lenders shall be extended to the first anniversary of the Existing Maturity Date (subject to satisfaction of the conditions set forth in Section 2.22(d)). In the event of such extension, the Commitment of each Non-extending Lender shall terminate on the Existing Maturity Date in effect for such Non-extending Lender prior to such extension and the outstanding principal balance of all Loans and other amounts payable hereunder to such Non-extending Lender shall become due and payable on such Existing Maturity Date and, subject to Section 2.22(c) below, the Aggregate Commitment hereunder shall be reduced by the Commitments of the Non-extending Lenders so terminated on such Existing Maturity Date. For purposes of clarity, it is acknowledged and agreed that the Maturity Date on any date of determination shall not be a date more than five (5) years after such date of determination, whether such determination is made before or after giving effect to any extension request made hereunder.

(c) In the event of any extension of the Existing Maturity Date pursuant to Section 2.22(b)(ii), the Borrower shall have the right on or before the Existing Maturity Date, at its own expense, to require any Non-extending Lender to transfer and assign without recourse (in accordance with and subject to the restrictions contained in Section 9.04) all its interests, rights (other than its rights to payments pursuant to Section 2.15, Section 2.16, Section 2.17 or Section 9.03 arising prior to the effectiveness of such assignment) and obligations under this Agreement to one or more banks or other financial institutions identified to the Non-extending Lender by the Borrower, which may include any existing Lender (each a "Replacement Lender"), provided that (i) such Replacement Lender, if not already a Lender hereunder, shall be subject to the approval of the Administrative Agent and the Issuing Banks (such approvals to not be unreasonably withheld) to the extent the consent of the Administrative Agent or the Issuing Banks would be required to effect an assignment under Section 9.04(b), (ii) such assignment shall become effective as of a date specified by the Borrower (which shall not be later than the Existing Maturity Date in effect for such Non-extending Lender prior to the effective date of the requested extension) and (iii) the Replacement Lender shall pay to such Non-extending Lender in immediately available funds on the effective date of such assignment the principal of and interest accrued to the date of payment on the outstanding principal amount Loans made by it hereunder and all other amounts accrued and unpaid for its account or otherwise owed to it hereunder on such date.

(d) As a condition precedent to each such extension of the Existing Maturity Date pursuant to Section 2.22(b)(ii), the Borrower shall (i) deliver to the Administrative Agent a certificate of the Borrower dated as of the Existing Maturity Date signed by a Responsible Officer of the Borrower certifying that, as of such date, both before and immediately after giving effect to such extension, (A) the representations and warranties of the Borrower set forth in this Agreement shall be true and correct in all material respects, except for any representation or warranty that is qualified by materiality or reference to Material Adverse Effect, which representation and warranty shall be true and correct in all respects (except, in each case, to the extent that any such representation or warranty specifically refers to an earlier date, in which case it shall be true and correct in all material respects, or in all respects, as applicable, as of such earlier date) and (B) no Default shall have occurred and be continuing, (ii) the Administrative Agent shall have received all fees and other amounts due and payable on or prior to such extension of the Existing Maturity Date, including, to the extent invoiced, reimbursement or payment of all out-of-pocket expenses required to be reimbursed or paid by the Borrower and (iii) first make such prepayments of the outstanding Loans and second provide such cash collateral (or make such other arrangements satisfactory to the applicable Issuing Bank) with respect to the outstanding Letters of Credit as shall be required such that, after giving effect to the termination of the Commitments of the Non-extending Lenders pursuant to Section 2.22(b) and any assignment pursuant to Section 2.22(c), the aggregate Revolving Credit Exposure less the face amount of any Letter of Credit supported by any such cash collateral (or other satisfactory arrangements) so provided does not exceed the aggregate amount of Commitments being extended.

(e) For the avoidance of doubt, no consent of any Lender (other than the existing Lenders participating in the extension of the Existing Maturity Date) shall be required for any extension of the Maturity Date pursuant to this Section 2.22 and the operation of this Section 2.22 in accordance with its terms is not an amendment subject to Section 9.02.

ARTICLE III

Representations and Warranties

The Borrower represents and warrants to the Lenders that:

SECTION 3.01 Corporate Existence; Authorization. The Borrower (a) has been duly incorporated and is validly existing as a corporation under the laws of its jurisdiction of incorporation, (b) has the requisite corporate power and authority to consummate the Transactions and (c) has duly taken all necessary corporate action to authorize the Transactions.

SECTION 3.02 Enforceability. This Agreement and each note delivered hereunder has been duly executed and delivered by the Borrower is the legal, valid and binding obligation of the Borrower, enforceable against it in accordance with its terms, and any other instrument or agreement required hereunder, when executed and delivered, will be similarly valid, binding and enforceable, except (in each case) to the extent that the enforcement thereof may be limited by bankruptcy, insolvency, reorganization or similar laws generally affecting creditors' rights and by general principles of equity.

SECTION 3.03 Financial Condition; No Material Adverse Change. (a) All fiscal year-end financial statements furnished by the Borrower to the Administrative Agent or any Lender have been prepared in accordance with GAAP consistently applied, except as noted therein, and fairly present the consolidated financial position and the consolidated results of operations of the Borrower as of the dates and for the periods presented. Financial statements and other information and data furnished to the Administrative Agent or any Lender other than fiscal year-end statements of the Borrower are in reasonable detail and present fairly the consolidated financial position and consolidated results of operations of the Borrower as of the dates and for the periods presented, subject to year-end audit adjustments.

(b) As of the Restatement Effective Date, there has been no material adverse change in the business or financial condition of the Borrower and its Subsidiaries, taken as a whole, except as disclosed in the Borrower's periodic reports filed with the SEC under the Securities Exchange Act of 1934 on or before the Restatement Effective Date.

SECTION 3.04 Compliance with Laws and Material Contractual Obligations. The operations of the Borrower and its Significant Subsidiaries are in compliance with (a) all Requirements of Law and (b) its obligations under material agreements to which it is a party, (i) except to the extent that the failure to comply therewith could not, in the aggregate, be reasonably expected to have a Material Adverse Effect or (ii) except as disclosed in the Borrower's periodic reports filed prior to the date of this Agreement with the SEC under the Securities Exchange Act of 1934. Neither the execution and delivery of this Agreement, nor the consummation of the transactions herein contemplated, will violate (x) any Requirement of Law, (y) violate or result in a default under any indenture or other material agreement or other material instrument binding upon the Borrower or any of its Subsidiaries or its assets, or give rise to a right thereunder to require any material payment to be made by the Borrower or any of its Subsidiaries or (z) result in the creation or imposition of, or the requirement to create, any lien or security interest on any asset of the Borrower or any of its Subsidiaries.

SECTION 3.05 No Material Litigation. No litigation, investigation or proceeding of or before any arbitrator or Governmental Authority is pending or, to the knowledge of the Borrower, threatened by or against the Borrower or any of its Subsidiaries or against any of its or their respective properties or revenues (a) with respect to this Agreement or any of the transactions contemplated hereby or (b) which could, insofar as the Borrower may reasonably foresee, have a Material Adverse Effect, except as disclosed in the Borrower's periodic reports filed with the SEC prior to the date of this Agreement under the Securities Exchange Act of 1934.

SECTION 3.06 Ownership of Property. Each of the Borrower and each of its Significant Subsidiaries has title in fee simple to or valid leasehold interests in all its real property material to the operation of its business, and title to or valid leasehold interests in all its other property useful and necessary in its business.

SECTION 3.07 Taxes. Each of the Borrower and each of its Significant Subsidiaries has filed or caused to be filed all Tax returns which to the knowledge of the Borrower are required to be filed and has paid all material taxes shown to be due and payable on said returns or on any assessments made against it or any of its property and all other material Taxes, fees or other charges imposed on it or any of its property by any Governmental Authority (other than those the amount or validity of which is currently being contested in good faith by appropriate proceedings and with respect to which reserves in conformity with GAAP have been provided on the books of the Borrower or the applicable Subsidiary, as the case may be); and no material Tax liens have been filed and, to the knowledge of the Borrower, no material claims are being asserted with respect to any such Taxes, fees or other charges.

SECTION 3.08 Subsidiaries. Schedule 3.08 contains an accurate list of all of the Subsidiaries of the Borrower existing as of the Restatement Effective Date, setting forth their respective jurisdictions of incorporation and the percentage of their respective Equity Interests owned by the Borrower and/or other Subsidiaries. All of the issued and outstanding shares of Equity Interests of such Subsidiaries have been duly authorized and issued and are fully paid and nonassessable.

SECTION 3.09 Investment Company Act; No Consents. Neither the Borrower nor any Subsidiary is an "Investment Company", as defined in, or subject to regulation under, the Investment Company Act of 1940, as amended. No authorizations, approvals or consents of, no filings or registrations with, any Governmental Authority are necessary for the consummation of the Transactions or for the validity or enforceability hereof or the notes delivered hereunder.

SECTION 3.10 ERISA. The Borrower is in compliance in all material respects with all applicable provisions of ERISA. The Borrower has not violated any provision of any Plan maintained or contributed to by the Borrower which could, insofar as the Borrower may reasonably foresee, have a Material Adverse Effect. No Reportable Event has occurred and is continuing with respect to any Plan initiated by the Borrower. The Borrower has met its minimum funding requirements under ERISA with respect to each Plan. Each Plan will be able to fulfill its benefit obligations as they come due in accordance with the Plan documents and under GAAP.

SECTION 3.11 Environmental. In the ordinary course of its business, the Borrower conducts an ongoing review of the effect of Environmental Laws on the business, operations, and properties of the Borrower, in the course of which it identifies and evaluates associated liabilities and costs (including any capital or operating expenditures required for clean-up or closure of properties presently or previously owned or operated, any capital or operating expenditures required to achieve or maintain compliance with environmental protection standards imposed by law or as a condition of any license, permit or contract, any related constraints on operating activities, including any periodic or permanent shutdown of any facility or reduction in the level of or change in the nature of operations conducted thereat and any actual or potential liabilities to third parties, including employees, and any related costs and expenses). On the basis of these reviews, the Borrower has reasonably concluded that Environmental Laws are unlikely to have a Material Adverse Effect. The Borrower hereby represents and warrants that its business and assets and those of its Subsidiaries are operated, and covenants that its and its Subsidiaries' business and assets will continue to be operated, in compliance with applicable Environmental Laws and that no enforcement action in respect thereof is threatened or pending that could, in the case of any failure to so comply or any such enforcement action, insofar as the Borrower may reasonably foresee, have a Material Adverse Effect, except as disclosed in the Borrower's periodic reports filed with the SEC on or prior to the date of this Agreement under the Securities Exchange Act of 1934.

SECTION 3.12 Margin Regulations. The Borrower is not engaged and will not engage, principally or as one of its important activities, in the business of purchasing or carrying Margin Stock, or extending credit for the purpose of purchasing or carrying Margin Stock, and no part of the proceeds of any Borrowing or Letter of Credit extension hereunder will be used to buy or carry any Margin Stock. Following the application of the proceeds of each Borrowing or drawing under each Letter of Credit, not more than 25% of the value of the assets (either of the Borrower only or of the Borrower and its Subsidiaries on a consolidated basis) will be Margin Stock.

SECTION 3.13 Disclosure. (a) As of the Restatement Effective Date, neither the Information Memorandum nor any of the other reports, financial statements, certificates or other information furnished by or on behalf of the Borrower or any Subsidiary to the Administrative Agent or any Lender in connection with the negotiation of this Agreement or delivered hereunder (as modified or supplemented by other information so furnished) contains any material misstatement of fact or omits to state any material fact necessary to make the statements therein, in the light of the circumstances under which they were made, not misleading; provided that, with respect to projected financial information, the Borrower represents only that such information was prepared in good faith based upon assumptions believed to be reasonable at the time.

(b) As of the Restatement Effective Date, to the best knowledge of the Borrower, the information included in the Beneficial Ownership Certification provided on or prior to the Restatement Effective Date to any Lender in connection with this Agreement is true and correct in all respects.

SECTION 3.14 Anti-Corruption Laws and Sanctions. The Borrower has implemented and maintains in effect policies and procedures designed to ensure compliance by the Borrower, its Subsidiaries and their respective directors, officers, employees and agents with Anti-Corruption Laws and applicable Sanctions, and the Borrower, its Subsidiaries and their respective officers and directors and to the knowledge of the Borrower its employees and agents, are in compliance with Anti-Corruption Laws and applicable Sanctions in all material respects. None of (a) the Borrower, any Subsidiary, any of their respective directors or officers, or employees, or (b) to the knowledge of the Borrower, any agent of the Borrower or any Subsidiary that will act in any capacity in connection with or benefit from the credit facility established hereby, is a Sanctioned Person. No Borrowing or Letter of Credit, use of proceeds or other Transactions will violate any Anti-Corruption Law or applicable Sanctions.

SECTION 3.15 Affected Financial Institutions. The Borrower is not an Affected Financial Institution.

SECTION 3.16 Plan Assets; Prohibited Transactions. None of the Borrower or any of its Subsidiaries is an entity deemed to hold “plan assets” (within the meaning of the Plan Asset Regulations), and neither the execution, delivery or performance of the Transactions, including the making of any Loan and the issuance of any Letter of Credit hereunder, will give rise to a non-exempt prohibited transaction under Section 406 of ERISA or Section 4975 of the Code.

ARTICLE IV

Conditions

SECTION 4.01 Restatement Effective Date. The obligations of the Lenders to make Loans and of the Issuing Banks to issue Letters of Credit hereunder shall not become effective until the date on which each of the following conditions is satisfied (or waived in accordance with Section 9.02):

(a) The Administrative Agent (or its counsel) shall have received (i) from each party hereto either (A) a counterpart of this Agreement signed on behalf of such party or (B) written evidence satisfactory to the Administrative Agent (which may include telecopy or electronic transmission of a signed signature page of this Agreement) that such party has signed a counterpart of this Agreement and (ii) duly executed copies of the Loan Documents and such other legal opinions, certificates, documents, instruments and agreements as the Administrative Agent shall reasonably request in connection with the Transactions, all in form and substance satisfactory to the Administrative Agent and its counsel and as further described in the list of closing documents attached as Exhibit D.

(b) The Administrative Agent shall have received a favorable written opinion (addressed to the Administrative Agent and the Lenders and dated the Restatement Effective Date) of Stoel Rives LLP, counsel for the Borrower, covering such matters relating to the Borrower, the Loan Documents or the Transactions as the Administrative Agent shall reasonably request. The Borrower hereby requests such counsel to deliver such opinion.

(c) The Administrative Agent shall have received such documents and certificates as the Administrative Agent or its counsel may reasonably request relating to the organization and valid existence of the Borrower, the authorization of the Transactions and any other legal matters relating to the

Borrower, the Loan Documents or the Transactions, all in form and substance satisfactory to the Administrative Agent and its counsel and as further described in the list of closing documents attached as Exhibit D.

(d) The Administrative Agent shall have received a certificate, dated the Restatement Effective Date and signed by a Responsible Officer of the Borrower, certifying (i) that the representations and warranties contained in Article III are true and correct as of such date and (ii) that no Default or Event of Default has occurred and is continuing as of such date.

(e) The Administrative Agent shall have received, for the account of the applicable Persons, payment of all accrued and unpaid interest and fees owing under the Existing Credit Agreement immediately prior to the Restatement Effective Date.

(f) The Administrative Agent shall have received all fees and other amounts due and payable on or prior to the Restatement Effective Date, including, to the extent invoiced, reimbursement or payment of all out-of-pocket expenses required to be reimbursed or paid by the Borrower hereunder.

(g) The Administrative Agent shall have received (i) satisfactory audited consolidated financial statements of the Borrower and its Subsidiaries on a consolidated basis for the two most recent fiscal years ended prior to the Restatement Effective Date as to which such financial statements are available and (ii) satisfactory unaudited interim consolidated financial statements of the Borrower and its Subsidiaries on a consolidated basis for each quarterly period ended subsequent to the date of the latest financial statements delivered pursuant to clause (i) as to which such financial statements are available.

(h) (i) The Administrative Agent shall have received, at least five days prior to the Restatement Effective Date (or such shorter period agreed to by the Administrative Agent in its sole discretion), all documentation and other information regarding the Borrower requested in connection with applicable "know your customer" and anti-money laundering rules and regulations, including the Patriot Act, to the extent requested in writing of the Borrower at least 10 days prior to the Restatement Effective Date and (ii) to the extent the Borrower qualifies as a "legal entity customer" under the Beneficial Ownership Regulation, at least five days prior to the Restatement Effective Date, any Lender that has requested, in a written notice to the Borrower at least 10 days prior to the Restatement Effective Date, a Beneficial Ownership Certification in relation to the Borrower shall have received such Beneficial Ownership Certification (provided that, upon the execution and delivery by such Lender of its signature page to this Agreement, the condition set forth in this clause (ii) shall be deemed to be satisfied).

(i) The Administrative Agent shall have received such other documents as the Administrative Agent or the Required Lenders (through the Administrative Agent) may reasonably request.

The Administrative Agent shall notify the Borrower and the Lenders of the Restatement Effective Date, and such notice shall be conclusive and binding. Notwithstanding the foregoing, the obligations of the Lenders to make Loans and of the Issuing Banks to issue Letters of Credit hereunder shall not become effective unless each of the foregoing conditions is satisfied (or waived pursuant to Section 9.02) at or prior to 3:00 p.m., New York City time, on November 3, 2021 (and, in the event such conditions are not so satisfied or waived, the Commitments shall terminate at such time).

SECTION 4.02 Each Credit Event. The obligation of each Lender to make a Loan on the occasion of any Borrowing, and of the Issuing Banks to issue, amend, renew or extend any Letter of Credit, is subject to the satisfaction of the following conditions:

(a) The representations and warranties of the Borrower set forth in this Agreement (other than, except in the case of the initial Loans, the representations and warranties set forth in Sections 3.04(b), 3.05(b) and 3.11) shall be true and correct in all material respects, except for any such representation or warranty that is qualified by materiality or reference to Material Adverse Effect, which representation and warranty shall be true and correct in all respects, on and as of the date of such Borrowing or the date of issuance, amendment, renewal or extension of such Letter of Credit (except, in each case, to the extent that any such representation or warranty specifically refers to an earlier date, in which case it shall be true and correct in all material respects, or in all respects, as applicable, as of such earlier date), as applicable.

(b) At the time of and immediately after giving effect to such Borrowing or the issuance, amendment, renewal or extension of such Letter of Credit, as applicable, no Default or Event of Default shall have occurred and be continuing.

Each Borrowing and each issuance, amendment, renewal or extension of a Letter of Credit shall be deemed to constitute a representation and warranty by the Borrower on the date thereof as to the matters specified in paragraphs (a) and (b) of this Section.

ARTICLE V

Affirmative Covenants

Until the Commitments have expired or been terminated and the principal of and interest on each Loan and all fees payable hereunder shall have been paid in full and all Letters of Credit shall have expired or terminated, in each case, without any pending draw, and all LC Disbursements shall have been reimbursed, the Borrower covenants and agrees with the Lenders that:

SECTION 5.01 Financial Statements and Other Information. The Borrower will furnish to the Administrative Agent and each Lender:

(a) as soon as practicable, but in any event within 120 days after the end of each fiscal year of the Borrower (commencing with the fiscal year ending December 31, 2021), a copy of the consolidated balance sheet of the Borrower and its audited consolidated Subsidiaries as at the end of such year and the related consolidated statements of income, of shareholders' equity and comprehensive income and of cash flows for such year, setting forth in each case in comparative form the figures for the previous year, audited by independent certified public accountants of nationally recognized standing (without any qualification or exception as to the scope of such audit) to the effect that such consolidated financial statements present fairly in all material respects the financial condition and results of operations of the Borrower and its consolidated Subsidiaries on a consolidated basis in accordance with GAAP consistently applied;

(b) as soon as practicable, but in any event not later than 60 days after the end of each of the first three quarterly periods of each fiscal year of the Borrower (commencing with the fiscal quarter ending September 30, 2021), the Form 10-Q as filed by the Borrower with the SEC for each such fiscal quarter, certified by an Authorized Officer as being complete and correct (subject to normal year-end audit adjustments); and

(c) together with the financial statements required hereunder, a compliance certificate in form and substance satisfactory to the Administrative Agent signed by its chief financial officer or chief accounting officer showing the calculations necessary to determine compliance with this Agreement, including its calculation of maintenance of Consolidated Indebtedness to Total Capitalization, and stating that no Default exists, or if any Default exists, stating the nature and status thereof.

All such financial statements shall be prepared in reasonable detail and in accordance with GAAP applied consistently throughout the periods reflected therein (except as approved by such accountants or officer, as the case may be, and disclosed therein).

SECTION 5.02 Certificates; Other Information. The Borrower shall furnish to the Administrative Agent and each Lender as soon as practicable, but in any event within ten days after the same are sent, copies of all financial statements and reports which the Borrower sends to its shareholders, and within ten days after the same are filed, copies of all financial statements and reports which the Borrower may make to, or file with, the SEC or any successor or analogous Governmental Authority. Promptly following any request therefor, the Borrower shall furnish (x) such other information regarding the operations, business affairs and financial condition of the Borrower or any Subsidiary, or compliance with the terms of this Agreement, as the Administrative Agent or any Lender may reasonably request, (y) information and documentation reasonably requested by the Administrative Agent or any Lender for purposes of compliance with applicable "know your customer" and anti-money laundering rules and regulations, including the Patriot Act and the Beneficial Ownership Regulation, and (z) any information regarding sustainability matters and practices of the Borrower and its Subsidiaries (including with respect to corporate governance, environmental, social and employee matters, respect for human rights, anti-corruption and anti-bribery) as the Administrative Agent or any Lender may reasonably request for purposes of compliance with any legal or regulatory requirement applicable to the Administrative Agent or any such Lender; and the Borrower shall furnish to the Administrative Agent and each Lender prompt written notice of any change in the information provided in the Beneficial Ownership Certification delivered to such Lender that would result in a change to the list of beneficial owners identified in such certification. The Borrower hereby acknowledges that (a) the Administrative Agent and/or the Arrangers will make available to the Lenders and the Issuing Banks materials and/or information provided by or on behalf of the Borrower hereunder (collectively, "Borrower Materials") by posting the Borrower Materials on IntraLinks or another similar electronic system (the "Platform") and (b) certain of the Lenders may be "public-side" Lenders (*i.e.,* Lenders that do not wish to receive material non-public information with respect to the Borrower or its securities) (each, a "Public Lender"). The Borrower hereby agrees that (w) all Borrower Materials that are to be made available to Public Lenders shall be clearly and conspicuously marked "PUBLIC" which, at a minimum, shall mean that the word "PUBLIC" shall appear prominently on the first page thereof; (x) by marking Borrower Materials "PUBLIC," the Borrower shall be deemed to have authorized the Administrative Agent, the Arrangers, the Issuing Banks and the Lenders to treat such Borrower Materials as either publicly available information or not material information (although it may be sensitive and proprietary) with respect to the Borrower or its securities for purposes of United States Federal and state securities laws; (y) all Borrower Materials marked "PUBLIC" are permitted to be made available through a portion of the Platform designated "Public Investor;" and (z) the Administrative Agent and the Arrangers shall be entitled to treat any Borrower Materials that are not marked "PUBLIC" as being suitable only for posting on a portion of the Platform not designated "Public Investor."

SECTION 5.03 Payment of Taxes. The Borrower shall, and shall cause each of its Subsidiaries to, pay, discharge or otherwise satisfy at or before maturity or before they become delinquent, as the case may be, all taxes, except when (a) the amount or validity thereof is currently being contested in good faith by appropriate proceedings or (b) reserves in conformity with GAAP with respect thereto have been provided on the books of the Borrower or such Subsidiary, as the case may be.

SECTION 5.04 Conduct of Business. The Borrower shall (a) carry on and conduct its business in substantially the same manner and in substantially the same fields of enterprise as it is presently conducted and to do all things necessary to remain duly incorporated, validly existing and in good standing as a domestic corporation in its jurisdiction of incorporation and maintain all requisite authority to conduct its business in each jurisdiction in which its business is conducted, and (b) comply with all Requirements of Law, except to the extent that failure to comply therewith could not, in the aggregate, have a Material Adverse Effect. The Borrower will maintain in effect and enforce policies and procedures designed to ensure compliance by the Borrower, its Subsidiaries and their respective directors, officers, employees and agents with Anti-Corruption Laws and applicable Sanctions.

SECTION 5.05 Maintenance of Property; Insurance. The Borrower shall, and shall cause each of its Subsidiaries to, (a) keep all property useful and necessary in its business in good working order and condition; (b) maintain with financially sound and reputable insurance companies insurance on such property in at least such amounts and against at least such risks as are usually insured against in the same general area by companies engaged in the same or a similar business; and (c) furnish to the Administrative Agent or any Lender, upon written request, full information as to the insurance carried.

SECTION 5.06 Inspection of Property; Books and Records; Discussions. The Borrower shall, and shall cause each of its Subsidiaries that have business operations to, (a) keep proper books of records and accounts in which entries in conformity with GAAP shall be made of all dealings and transactions in relation to its business and activities and (b) permit representatives of the Administrative Agent or any Lender, at such Person's expense, to visit and inspect any of its properties and examine and make abstracts from any of its books and records upon reasonable notice and during regular working hours, and to discuss the business, operations, properties and financial and other condition of the Borrower and its Subsidiaries with officers and employees of the Borrower and its Subsidiaries.

SECTION 5.07 Notices. The Borrower shall promptly give notice to the Administrative Agent and each Lender of (a) the occurrence of any Default; (b) any litigation, investigation or proceeding involving the Borrower or any of its Subsidiaries which, if not cured or if adversely determined, as the case may be, would have a Material Adverse Effect; (c) any change in any Debt Rating and (d) any Pricing Certificate Inaccuracy. Each notice pursuant to this Section 5.07 shall be accompanied by a statement of an Authorized Officer setting forth details of the occurrence referred to therein and stating what action the Borrower proposes to take with respect thereto.

SECTION 5.08 Use of Proceeds and Letters of Credit. The proceeds of the Loans will be used only to finance the working capital needs, and for general corporate purposes, of the Borrower and its Subsidiaries (other than Hostile Acquisitions). No part of the proceeds of any Loan will be used, whether directly or indirectly, for any purpose that entails a violation of any of the regulations of the Federal Reserve Board, including Regulations T, U and X. Letters of Credit will be issued only to support the Borrower and its Subsidiaries. The Borrower will not request any Borrowing or Letter of Credit, and the Borrower shall not use, and shall procure that its Subsidiaries and its or their respective directors, officers, employees and agents shall not use, the proceeds of any Borrowing or Letter of Credit (i) in furtherance of an offer, payment, promise to pay, or authorization of the payment or giving of money, or anything else of value, to any Person in violation of any Anti-Corruption Laws, (ii) for the purpose of funding, financing or facilitating any activities, business or transaction of or with any Sanctioned Person, or in any Sanctioned Country, except to the extent permitted for a Person required to comply with Sanctions, or (iii) in any manner that would result in the violation of any Sanctions applicable to any party hereto.

SECTION 5.09 Debt Rating. The Borrower shall cause NW Natural to maintain at all times a Debt Rating from both Moody's and S&P.

ARTICLE VI

Negative Covenants

Until the Commitments have expired or terminated and the principal of and interest on each Loan and all fees payable hereunder have been paid in full and all Letters of Credit have expired or terminated, in each case, without any pending draw, and all LC Disbursements shall have been reimbursed, the Borrower covenants and agrees with the Lenders that it will not:

SECTION 6.01 Fundamental Changes. (a) With respect to the Borrower or any Significant Subsidiary, without the consent of the Administrative Agent and the Required Lenders enter into any transaction of merger or consolidation or amalgamation, or liquidate, wind up or dissolve (or suffer any liquidation or dissolution), convey, sell, lease, transfer or otherwise dispose of, in one transaction or a series of transactions, all or substantially all of the consolidated assets of the Borrower and its Subsidiaries, taken as a whole, except (i) for sales, leases or rentals of property or assets in the ordinary course of business, (ii) that any consolidated Subsidiary of the Borrower may be merged or consolidated with or into the Borrower (provided that the Borrower shall be the continuing or surviving corporation) or with any one or more Subsidiaries of the Borrower (provided that if any such transaction shall be between a Subsidiary and a wholly-owned Subsidiary, the wholly-owned Subsidiary shall be the continuing or surviving corporation), (iii) any Subsidiary may sell, lease, transfer or otherwise dispose of any or all of its assets (upon voluntary liquidation or otherwise) to the Borrower or another wholly-owned Subsidiary of the Borrower and (iv) the Borrower may be merged with any other Person if (x) the Borrower is the surviving corporation, (y) immediately after giving effect to such merger, there shall exist no condition or event which constitutes an Event of Default or which, with the giving of notice or lapse of time or both, would constitute an Event of Default, and (z) all representations and warranties contained in Article III hereof are true and correct in all material respects (except for any such representation and warranty that is qualified by materiality or reference to Material Adverse Effect, which representation shall be true and correct in all respects) on and as of the date of the consummation of such merger, and after giving effect thereto, as though restated on and as of such date (except to the extent that such representations and warranties specifically refer to an earlier date, in which case they shall be true and correct in all material respects (except for any such representation and warranty that is qualified by materiality or reference to Material Adverse Effect, which representation shall be true and correct in all respects) as of such earlier date).

(b) With respect to the Borrower, without the consent of the Administrative Agent and the Required Lenders, cease to own, directly or indirectly, 100% of the Equity Interests of NW Natural (other than a single share of the junior preferred capital stock of NW Natural held by an independent third party), free and clear of any lien, pledge, charge or other security interest.

SECTION 6.02 Financial Covenant. Maintenance of Consolidated Indebtedness to Total Capitalization. As at the end of any fiscal quarter of the Borrower, permit Consolidated Indebtedness to be greater than 70% of Total Capitalization.

ARTICLE VII

Events of Default

SECTION 7.01 Events of Default. If any of the following events ("Events of Default") shall occur:

(a) The Borrower shall fail to pay any principal of the Loans when due in accordance with the terms hereof; or

(b) The Borrower shall fail to pay any interest on the Loans, or any other amount payable by the Borrower hereunder, within five days after any such amount becomes due in accordance with the terms hereof; or

(c) Any representation or warranty made or deemed made by the Borrower herein shall prove to have been incorrect in any material respect on or as of the date made; or

(d) The Borrower shall default in the observance or performance of any covenant described in Sections 5.08, 6.01 or 6.02; or the Borrower shall default in the observance or performance of any other agreement or covenant contained in this Agreement, and such default shall continue unremedied for a period of 30 days after the earlier of (i) the date a Responsible Officer has knowledge of such default or (ii) written notice of such default shall have been given to the Borrower by the Administrative Agent or any Lender; or

(e) The Borrower or any Subsidiary of the Borrower shall fail to make any payment in respect of any Indebtedness having singly or in the aggregate an outstanding amount in excess of $50 million when due or within any applicable grace period; or

(f) A final judgment for the payment of money exceeding an aggregate of $15 million shall be rendered or entered against the Borrower and/or any Significant Subsidiary and the same shall remain undischarged for a period of 60 days during which execution shall not be effectively stayed or contested in good faith; or

(g) An involuntary proceeding shall be commenced or an involuntary petition shall be filed seeking (i) liquidation, reorganization or other relief in respect of the Borrower or any Significant Subsidiary or its debts, or of a substantial part of its assets, under any Federal, state or foreign bankruptcy, insolvency, receivership or similar law now or hereafter in effect or (ii) the appointment of a receiver, trustee, custodian, sequestrator, conservator or similar official for the Borrower or any Significant Subsidiary or for a substantial part of its assets, and, in any such case, such proceeding or petition shall continue undismissed for 60 days or an order or decree approving or ordering any of the foregoing shall be entered; or

(h) The Borrower or any Significant Subsidiary shall (i) voluntarily commence any proceeding or file any petition seeking liquidation, reorganization or other relief under any Federal, state or foreign bankruptcy, insolvency, receivership or similar law now or hereafter in effect, (ii) consent to the institution of, or fail to contest in a timely and appropriate manner, any proceeding or petition described in clause (g) above, (iii) apply for or consent to the appointment of a receiver, trustee, custodian, sequestrator, conservator or similar official for the Borrower or any Significant Subsidiary or for a substantial part of its assets, (iv) file an answer admitting the material allegations of a petition filed against it in any such proceeding, (v) make a general assignment for the benefit of creditors, (vi) become unable, admit in writing its inability or fail generally to pay its debts as they become due or (vii) take any action for the purpose of effecting any of the foregoing;

(i) a Change in Control shall occur;

(j) an ERISA Event shall have occurred (other than NW Natural's December 22, 2013 withdrawal from the Western States Office and Professional Employees International Union Pension Fund) that, in the opinion of the Required Lenders, when taken together with all other ERISA Events that have occurred, could reasonably be expected to result in a Material Adverse Effect; or

(k) any material provision of any Loan Document, at any time after its execution and delivery and for any reason other than as expressly permitted hereunder or thereunder or satisfaction in full of all Obligations, ceases to be in full force and effect; or the Borrower or any Subsidiary contests in writing the validity or enforceability of any provision of any Loan Document; or, prior to satisfaction in full of all Obligations, the Borrower denies in writing that it has any or further liability or obligation under any Loan Document, or the Borrower purports in writing to revoke, terminate or rescind any Loan Document other than in compliance with Section 9.02;

then, and in every such event (other than an event with respect to the Borrower, described in clause (g) or (h) above), and at any time thereafter during the continuance of such event, the Administrative Agent may, and at the request of the Required Lenders shall, by notice to the Borrower, take either or both of the following actions, at the same or different times: (i) terminate the Commitments, and thereupon the Commitments shall terminate immediately, and/or (ii) declare the Loans then outstanding to be due and payable in whole (or in part, in which case any principal not so declared to be due and payable may thereafter be declared to be due and payable), and thereupon the principal of the Loans so declared to be due and payable, together with accrued interest thereon and all fees and other Obligations of the Borrower accrued hereunder, shall become due and payable immediately, without presentment, demand, protest or other notice of any kind, all of which are hereby waived by the Borrower, (iii) require cash collateral for the LC Exposure as required in Section 2.06(j) hereof and (iv) exercise on behalf of itself, the Lenders and the Issuing Banks all rights and remedies available to it, the Lenders and the Issuing Banks under the Loan Documents and applicable law; and in case of any event with respect to the Borrower described in clause (g) or (h) of this Section, the Commitments shall automatically terminate and the principal of the Loans then outstanding and cash collateral for the LC Exposure, together with accrued interest thereon and all fees and other Obligations accrued hereunder and under the other Loan Documents, shall automatically become due and payable, and the obligation of the Borrower to cash collateralize the LC Exposure as provided in clause (iii) above shall automatically become effective, in each case, without presentment, demand, protest or other notice of any kind, all of which are hereby waived by the Borrower. Upon the occurrence and during the continuance of an Event of Default, the Administrative Agent may, and at the request of the Required Lenders shall, exercise any rights and remedies provided to the Administrative Agent under the Loan Documents or at law or equity.

SECTION 7.02 Application of Payments. Notwithstanding anything herein to the contrary, following the occurrence and during the continuance of an Event of Default, and notice thereof to the Administrative Agent by the Borrower or the Required Lenders, all payments received on account of the Obligations shall, subject to Section 2.21, be applied by the Administrative Agent as follows:

(i) first, to payment of that portion of the Obligations constituting fees, indemnities, expenses and other amounts payable to the Administrative Agent (including fees and disbursements and other charges of counsel to the Administrative Agent payable under

Section 9.03 and amounts pursuant to Section 2.12(c) payable to the Administrative Agent in its capacity as such);

(ii) second, to payment of that portion of the Obligations constituting fees, expenses, indemnities and other amounts (other than principal, reimbursement obligations in respect of LC Disbursements, interest and Letter of Credit fees) payable to the Lenders and the Issuing Banks (including fees and disbursements and other charges of counsel to the Lenders and the Issuing Banks payable under Section 9.03) arising under the Loan Documents, ratably among them in proportion to the respective amounts described in this clause (ii) payable to them;

(iii) third, to payment of that portion of the Obligations constituting accrued and unpaid Letter of Credit fees and charges and interest on the Loans and unreimbursed LC Disbursements, ratably among the Lenders and the Issuing Banks in proportion to the respective amounts described in this clause (iii) payable to them;

(iv) fourth, (A) to payment of that portion of the Obligations constituting unpaid principal of the Loans and unreimbursed LC Disbursements and (B) to cash collateralize that portion of LC Exposure comprising the undrawn amount of Letters of Credit to the extent not otherwise cash collateralized by the Borrower pursuant to Section 2.06 or 2.21, ratably among the Lenders and the Issuing Banks in proportion to the respective amounts described in this clause (iv) payable to them; provided that (x) any such amounts applied pursuant to subclause (B) above shall be paid to the Administrative Agent for the ratable account of the applicable Issuing Bank to cash collateralize Obligations in respect of Letters of Credit, (y) subject to Section 2.06 or 2.21, amounts used to cash collateralize the aggregate amount of Letters of Credit pursuant to this clause (iv) shall be used to satisfy drawings under such Letters of Credit as they occur and (z) upon the expiration of any Letter of Credit (without any pending drawings), the pro rata share of cash collateral shall be distributed to the other Obligations, if any, in the order set forth in this Section 7.02;

(v) fifth, to the payment in full of all other Obligations, in each case ratably among the Administrative Agent, the Lenders and the Issuing Banks based upon the respective aggregate amounts of all such Obligations owing to them in accordance with the respective amounts thereof then due and payable; and

(vi) finally, the balance, if any, after all Obligations have been indefeasibly paid in full, to the Borrower or as otherwise required by law.

If any amount remains on deposit as cash collateral after all Letters of Credit have either been fully drawn or expired (without any pending drawings), such remaining amount shall be applied to the other Obligations, if any, in the order set forth above.

ARTICLE VIII

The Administrative Agent

SECTION 8.01 Authorization and Action. (a) Each Lender and the Issuing Banks hereby irrevocably appoints the entity named as Administrative Agent in the heading of this Agreement and its successors and assigns to serve as the administrative agent under the Loan Documents and each Lender and the Issuing Banks authorizes the Administrative Agent to take such actions as agent on its behalf and to exercise such powers under this Agreement and the other Loan Documents as are delegated to the Administrative Agent under such agreements and to exercise such powers as are reasonably incidental thereto. Without limiting the foregoing, each Lender and the Issuing Banks hereby authorizes the Administrative Agent to execute and deliver, and to perform its obligations under, each of the Loan Documents to which the Administrative Agent is a party, to exercise all rights, powers and remedies that the Administrative Agent may have under such Loan Documents.

(b) As to any matters not expressly provided for herein and in the other Loan Documents (including enforcement or collection), the Administrative Agent shall not be required to exercise any discretion or take any action, but shall be required to act or to refrain from acting (and shall be fully protected in so acting or refraining from acting) upon the written instructions of the Required Lenders (or such other number or percentage of the Lenders as shall be necessary, pursuant to the terms in the Loan Documents), and, unless and until revoked in writing, such instructions shall be binding upon each Lender and the Issuing Banks; provided, however, that the Administrative Agent shall not be required to take any action that (i) the Administrative Agent in good faith believes exposes it to liability unless the Administrative Agent receives an indemnification and is exculpated in a manner satisfactory to it from the Lenders and the Issuing Banks with respect to such action or (ii) is contrary to this Agreement or any other Loan Document or applicable law, including any action that may be in violation of the automatic stay under any requirement of law relating to bankruptcy, insolvency or reorganization or relief of debtors or that may effect a forfeiture, modification or termination of property of a Defaulting Lender in violation of any requirement of law relating to bankruptcy, insolvency or reorganization or relief of debtors; provided, further, that the Administrative Agent may seek clarification or direction from the Required Lenders prior to the exercise of any such instructed action and may refrain from acting until such clarification or direction has been provided. Except as expressly set forth in the Loan Documents, the Administrative Agent shall not have any duty to disclose, and shall not be liable for the failure to disclose, any information relating to the Borrower, any Subsidiary or any Affiliate of any of the foregoing that is communicated to or obtained by the Person serving as Administrative Agent or any of its Affiliates in any capacity. Nothing in this Agreement shall require the Administrative Agent to expend or risk its own funds or otherwise incur any financial liability in the performance of any of its duties hereunder or in the exercise of any of its rights or powers if it shall have reasonable grounds for believing that repayment of such funds or adequate indemnity against such risk or liability is not reasonably assured to it.

(c) In performing its functions and duties hereunder and under the other Loan Documents, the Administrative Agent is acting solely on behalf of the Lenders and the Issuing Banks (except in limited circumstances expressly provided for herein relating to the maintenance of the Register), and its duties are entirely mechanical and administrative in nature. Without limiting the generality of the foregoing:

(i) the Administrative Agent does not assume and shall not be deemed to have assumed any obligation or duty or any other relationship as the agent, fiduciary or trustee of or for any Lender, Issuing Bank or holder of any other obligation other than as expressly set forth herein and in the other Loan Documents, regardless of whether a Default or an Event of Default has occurred and is continuing (and it is understood and agreed that the use of the term "agent" (or any similar term) herein or in any other Loan Document with reference to the Administrative Agent is not intended to connote any fiduciary duty or other implied (or express) obligations arising under agency doctrine of any applicable law, and that such term is used as a matter of market custom and is intended to create or reflect only an administrative relationship between contracting parties); additionally, each Lender agrees that it will not assert any claim against the Administrative Agent based on an alleged breach of fiduciary duty by the Administrative Agent in connection with this Agreement and the transactions contemplated hereby;

(ii) nothing in this Agreement or any Loan Document shall require the Administrative Agent to account to any Lender for any sum or the profit element of any sum received by the Administrative Agent for its own account;

(d) The Administrative Agent may perform any of its duties and exercise its rights and powers hereunder or under any other Loan Document by or through any one or more sub-agents appointed by the Administrative Agent. The Administrative Agent and any such sub-agent may perform any of their respective duties and exercise their respective rights and powers through their respective Related Parties. The exculpatory provisions of this Article shall apply to any such sub-agent and to the Related Parties of the Administrative Agent and any such sub-agent, and shall apply to their respective activities pursuant to this Agreement. The Administrative Agent shall not be responsible for the negligence or misconduct of any sub-agent except to the extent that a court of competent jurisdiction determines in a final and nonappealable judgment that the Administrative Agent acted with gross negligence or willful misconduct in the selection of such sub-agent.

(e) None of any Co-Syndication Agents, the Sustainability Structuring Agent or any Arrangers shall have obligations or duties whatsoever in such capacity under this Agreement or any other Loan Document and shall incur no liability hereunder or thereunder in such capacity, but all such Persons shall have the benefit of the indemnities provided for hereunder.

(f) In case of the pendency of any proceeding with respect to the Borrower under any Federal, state or foreign bankruptcy, insolvency, receivership or similar law now or hereafter in effect, the Administrative Agent (irrespective of whether the principal of any Loan or any other obligation shall then be due and payable as herein expressed or by declaration or otherwise and irrespective of whether the Administrative Agent shall have made any demand on the Borrower) shall be entitled and empowered (but not obligated) by intervention in such proceeding or otherwise:

(i) to file and prove a claim for the whole amount of the principal and interest owing and unpaid in respect of the Loans, LC Disbursements and all other Obligations that are owing and unpaid and to file such other documents as may be necessary or advisable in order to have the claims of the Lenders, the Issuing Banks and the Administrative Agent (including any claim under Sections 2.12, 2.13, 2.15, 2.17 and 9.03) allowed in such judicial proceeding; and

(ii) to collect and receive any monies or other property payable or deliverable on any such claims and to distribute the same;

and any custodian, receiver, assignee, trustee, liquidator, sequestrator or other similar official in any such proceeding is hereby authorized by each Lender and each Issuing Bank to make such payments to the Administrative Agent and, in the event that the Administrative Agent shall consent to the making of such payments directly to the Lenders and the Issuing Banks, to pay to the Administrative Agent any amount due to it, in its capacity as the Administrative Agent, under the Loan Documents (including under Section 9.03). Nothing contained herein shall be deemed to authorize the Administrative Agent to authorize or consent to or accept or adopt on behalf of any Lender or Issuing Bank any plan of reorganization, arrangement, adjustment or composition affecting the Obligations or the rights of any Lender or Issuing Bank or to authorize the Administrative Agent to vote in respect of the claim of any Lender or Issuing Bank in any such proceeding.

(g) The provisions of this Article are solely for the benefit of the Administrative Agent, the Sustainability Structuring Agent, the Lenders and the Issuing Banks, and, except solely to the extent of the Borrower's rights to consent pursuant to and subject to the conditions set forth in this Article, none of the Borrower or any Subsidiary, or any of their respective Affiliates, shall have any rights as a third party beneficiary under any such provisions.

SECTION 8.02 Administrative Agent's Reliance, Indemnification, Etc. (a) Neither the Administrative Agent nor any of its Related Parties shall be (i) liable for any action taken or omitted to be taken by it under or in connection with this Agreement or the other Loan Documents (x) with the consent of or at the request of the Required Lenders (or such other number or percentage of the Lenders as shall be necessary, or as the Administrative Agent shall believe in good faith to be necessary, under the circumstances as provided in the Loan Documents) or (y) in the absence of its own gross negligence or willful misconduct (such absence to be presumed unless otherwise determined by a court of competent jurisdiction by a final and nonappealable judgment) or (ii) responsible in any manner to any of the Lenders for any recitals, statements, representations or warranties made by the Borrower or any officer thereof contained in this Agreement or any other Loan Document or in any certificate, report, statement or other document referred to or provided for in, or received by the Administrative Agent under or in connection with, this Agreement or any other Loan Document or for the value, validity, effectiveness, genuineness, enforceability or sufficiency of this Agreement or any other Loan Document (including, for the avoidance of doubt, in connection with the Administrative Agent's reliance on any Electronic

Signature transmitted by telecopy, emailed pdf, or any other electronic means that reproduces an image of an actual executed signature page) or for any failure of the Borrower to perform its obligations hereunder or thereunder.

(b) The Administrative Agent shall be deemed not to have knowledge of any Default unless and until written notice thereof (stating that it is a "notice of default") is given to the Administrative Agent by the Borrower, a Lender or any Issuing Bank, and the Administrative Agent shall not be responsible for or have any duty to ascertain or inquire into (i) any statement, warranty or representation made in or in connection with any Loan Document, (ii) the contents of any certificate, report or other document delivered thereunder or in connection therewith, (iii) the performance or observance of any of the covenants, agreements or other terms or conditions set forth in any Loan Document or the occurrence of any Default, (iv) the sufficiency, validity, enforceability, effectiveness or genuineness of any Loan Document or any other agreement, instrument or document, or (v) the satisfaction of any condition set forth in Article IV or elsewhere in any Loan Document, other than to confirm receipt of items expressly required to be delivered to the Administrative Agent or satisfaction of any condition that expressly refers to the matters described therein being acceptable or satisfactory to the Administrative Agent.

(c) Without limiting the foregoing, the Administrative Agent (i) may treat the payee of any promissory note as its holder until such promissory note has been assigned in accordance with Section 9.04, (ii) may rely on the Register to the extent set forth in Section 9.04(b), (iii) may consult with legal counsel (including counsel to the Borrower), independent public accountants and other experts selected by it, and shall not be liable for any action taken or omitted to be taken in good faith by it in accordance with the advice of such counsel, accountants or experts, (iv) makes no warranty or representation to any Lender or Issuing Bank and shall not be responsible to any Lender or Issuing Bank for any statements, warranties or representations made by or on behalf of the Borrower in connection with this Agreement or any other Loan Document, (v) in determining compliance with any condition hereunder to the making of a Loan, or the issuance of a Letter of Credit, that by its terms must be fulfilled to the satisfaction of a Lender or any Issuing Bank, may presume that such condition is satisfactory to such Lender or Issuing Bank unless the Administrative Agent shall have received notice to the contrary from such Lender or Issuing Bank sufficiently in advance of the making of such Loan or the issuance of such Letter of Credit and (vi) shall be entitled to rely on, and shall incur no liability under or in respect of this Agreement or any other Loan Document by acting upon, any notice, consent, certificate or other instrument or writing (which writing may be a fax, any electronic message, Internet or intranet website posting or other distribution) or any statement made to it orally or by telephone and believed by it to be genuine and signed or sent or otherwise authenticated by the proper party or parties (whether or not such Person in fact meets the requirements set forth in the Loan Documents for being the maker thereof).

SECTION 8.03 Posting of Communications. (a) The Borrower agrees that the Administrative Agent may, but shall not be obligated to, make any Communications available to the Lenders and the Issuing Banks by posting the Communications on IntraLinks™, DebtDomain, SyndTrak, ClearPar or any other electronic platform chosen by the Administrative Agent to be its electronic transmission system (the "Approved Electronic Platform").

(b) Although the Approved Electronic Platform and its primary web portal are secured with generally-applicable security procedures and policies implemented or modified by the Administrative Agent from time to time (including, as of the Restatement Effective Date, a user ID/password authorization system) and the Approved Electronic Platform is secured through a per-deal authorization method whereby each user may access the Approved Electronic Platform only on a deal-by-deal basis, each of the Lenders, the Issuing Banks and the Borrower acknowledges and agrees that the distribution of material through an electronic medium is not necessarily secure, that the Administrative Agent is not responsible for approving or vetting the representatives or contacts of any Lender that are added to the Approved Electronic Platform, and that there are confidentiality and other risks associated with such distribution. Each of the Lenders, the Issuing Banks and the Borrower hereby approves distribution of the Communications through the Approved Electronic Platform and understands and assumes the risks of such distribution.

(c) THE APPROVED ELECTRONIC PLATFORM AND THE COMMUNICATIONS ARE PROVIDED "AS IS" AND "AS AVAILABLE". THE APPLICABLE PARTIES (AS DEFINED BELOW) DO NOT WARRANT THE ACCURACY OR COMPLETENESS OF THE COMMUNICATIONS, OR THE ADEQUACY OF THE APPROVED ELECTRONIC PLATFORM AND EXPRESSLY DISCLAIM LIABILITY FOR ERRORS OR OMISSIONS IN THE APPROVED ELECTRONIC PLATFORM AND THE COMMUNICATIONS. NO WARRANTY OF ANY KIND, EXPRESS, IMPLIED OR STATUTORY, INCLUDING ANY WARRANTY OF MERCHANTABILITY, FITNESS FOR A PARTICULAR PURPOSE, NON-INFRINGEMENT OF THIRD PARTY RIGHTS OR FREEDOM FROM VIRUSES OR OTHER CODE DEFECTS, IS MADE BY THE APPLICABLE PARTIES IN CONNECTION WITH THE COMMUNICATIONS OR THE APPROVED ELECTRONIC PLATFORM. IN NO EVENT SHALL THE ADMINISTRATIVE AGENT, ANY ARRANGERS, THE SUSTAINABILITY STRUCTURING AGENT, ANY CO-SYNDICATION AGENTS OR ANY OF THEIR RESPECTIVE RELATED PARTIES (COLLECTIVELY, "APPLICABLE PARTIES") HAVE ANY LIABILITY TO THE BORROWER, ANY LENDER, ANY ISSUING BANK OR ANY OTHER PERSON OR ENTITY FOR DAMAGES OF ANY KIND, INCLUDING DIRECT OR INDIRECT, SPECIAL, INCIDENTAL OR CONSEQUENTIAL DAMAGES, LOSSES OR EXPENSES (WHETHER IN TORT, CONTRACT OR OTHERWISE) ARISING OUT OF THE BORROWER'S OR THE ADMINISTRATIVE AGENT'S TRANSMISSION OF COMMUNICATIONS THROUGH THE INTERNET OR THE APPROVED ELECTRONIC PLATFORM.

"Communications" means, collectively, any notice, demand, communication, information, document or other material provided by or on behalf of the Borrower pursuant to any Loan Document or the transactions contemplated therein which is distributed by the Administrative Agent, any Lender or any Issuing Bank by means of electronic communications pursuant to this Section, including through an Approved Electronic Platform.

(d) Each Lender and Issuing Bank agrees that notice to it (as provided in the next sentence) specifying that Communications have been posted to the Approved Electronic Platform shall constitute effective delivery of the Communications to such Lender for purposes of the Loan Documents. Each Lender and Issuing Bank agrees (i) to notify the Administrative Agent in writing (which could be in the form of electronic communication) from time to time of such Lender's or Issuing Bank's (as applicable) email address to which the foregoing notice may be sent by electronic transmission and (ii) that the foregoing notice may be sent to such email address.

(e) Each of the Lenders, the Issuing Banks and the Borrower agrees that the Administrative Agent may, but (except as may be required by applicable law) shall not be obligated to, store the Communications on the Approved Electronic Platform in accordance with the Administrative Agent's generally applicable document retention procedures and policies.

(f) Nothing herein shall prejudice the right of the Administrative Agent, any Lender or any Issuing Bank to give any notice or other communication pursuant to any Loan Document in any other manner specified in such Loan Document.

SECTION 8.04 The Administrative Agent Individually. With respect to its Commitment, Loans, Letter of Credit Commitments and Letters of Credit, the Person serving as the Administrative Agent shall have and may exercise the same rights and powers hereunder and is subject to the same obligations and liabilities as and to the extent set forth herein for any other Lender or Issuing Bank, as the case may be. The terms "Issuing Bank", "Lenders", "Required Lenders" and any similar terms shall, unless the context clearly otherwise indicates, include the Administrative Agent in its individual capacity as a Lender, Issuing Bank or as one of the Required Lenders, as applicable. The Person serving as the Administrative Agent and its Affiliates may accept deposits from, lend money to, own securities of, act as the financial advisor or in any other advisory capacity for and generally engage in any kind of banking, trust or other business with, the Borrower, any Subsidiary or any Affiliate of any of the foregoing as if such Person was not acting as the Administrative Agent and without any duty to account therefor to the Lenders or the Issuing Banks.

SECTION 8.05 Successor Administrative Agent. Subject to the appointment and acceptance of a successor Administrative Agent as provided in this paragraph, the Administrative Agent may resign at any time by notifying the Lenders, the Issuing Banks and the Borrower. Upon any such resignation, the Required Lenders shall have the right, in consultation with the Borrower, to appoint a successor. If no successor shall have been so appointed by the Required Lenders and shall have accepted such appointment within 30 days after the retiring Administrative Agent gives notice of its resignation, then the retiring Administrative Agent may, on behalf of the Lenders and the Issuing Banks, appoint a successor Administrative Agent which shall be a bank with an office in New York, New York, or an Affiliate of any such bank. Upon the acceptance of its appointment as Administrative Agent hereunder by a successor, such successor shall succeed to and become vested with all the rights, powers, privileges and duties of the retiring Administrative Agent, and the retiring Administrative Agent shall be discharged from its duties and obligations hereunder. The fees payable by the Borrower to a successor Administrative Agent shall be the same as those payable to its predecessor unless otherwise agreed between the Borrower and such successor. After the Administrative Agent's resignation hereunder, the provisions of this Article and Section 9.03, as well as any exculpatory, reimbursement and indemnification provisions set forth in any other Loan Document, shall continue in effect for the benefit of such retiring Administrative Agent, its sub agents and their respective Related Parties in respect of any actions taken or omitted to be taken by any of them while it was acting as Administrative Agent.

SECTION 8.06 Acknowledgments of Lenders and Issuing Banks. (a) Each Lender and each Issuing Bank represents and warrants that (i) the Loan Documents set forth the terms of a commercial lending facility, (ii) it is engaged in making, acquiring or holding commercial loans and in providing other facilities set forth herein as may be applicable to such Lender or Issuing Bank, in each case in the ordinary course of business, and not for the purpose of purchasing, acquiring or holding any other type of financial instrument (and each Lender and each Issuing Bank agrees not to assert a claim in contravention of the foregoing), (iii) it has, independently and without reliance upon the Administrative Agent, any Arranger, any Co-Syndication Agent, the Sustainability Structuring Agent or any other Lender or Issuing Bank, or any of the Related Parties of any of the foregoing, and based on such documents and information as it has deemed appropriate, made its own credit analysis and decision to enter into this Agreement as a Lender, and to make, acquire or hold Loans hereunder and (iv) it is sophisticated with respect to decisions to make, acquire and/or hold commercial loans and to provide other facilities set forth herein, as may be applicable to such Lender or such Issuing Bank, and either it, or the Person exercising discretion in making its decision to make, acquire and/or hold such commercial loans or to provide such other facilities, is experienced in making, acquiring or holding such commercial loans or providing such other facilities. Each Lender and each Issuing Bank also acknowledges that it will, independently and without reliance upon the Administrative Agent, any Arranger, any Co-Syndication Agent, the Sustainability Structuring Agent or any other Lender or Issuing Bank, or any of the Related Parties of any of the foregoing, and based on such documents and information (which may contain material, non-public information within the meaning of the United States securities laws concerning the Borrower and its Affiliates) as it shall from time to time deem appropriate, continue to make its own decisions in taking or not taking action under or based upon this Agreement, any other Loan Document or any related agreement or any document furnished hereunder or thereunder. Each Lender and each Issuing Bank also acknowledges and agrees that none of the Administrative Agent, any Arranger, any Co-Syndication Agent, the Sustainability Structuring Agent acting in such capacities have made any assurances as to (i) whether the credit facility evidenced by the Loan Documents (the "Facility") meets such Lender's or Issuing Bank's criteria or expectations with regard to environmental impact and sustainability performance, (ii) whether any characteristics of the Facility, including the characteristics of the relevant key performance indicators to which the Borrower will link a potential margin step-up or step-down, including their environmental and sustainability criteria, meet any industry standards for sustainability-linked credit facilities and (b) each Lender and Issuing Bank has performed its own independent investigation and analysis of the Facility and whether the Facility meets its own criteria or expectations with regard to environmental impact and/or sustainability performance.

(b) Each Lender, by delivering its signature page to this Agreement on the Restatement Effective Date, or delivering its signature page to an Assignment and Assumption or any other Loan Document pursuant to which it shall become a Lender hereunder, shall be deemed to have acknowledged receipt of, and consented to and approved, each Loan Document and each other document required to be delivered to, or be approved by or satisfactory to, the Administrative Agent or the Lenders on the Restatement Effective Date.

(c)

(i) Each Lender hereby agrees that (x) if the Administrative Agent notifies such Lender that the Administrative Agent has determined in its sole discretion that any funds received by such Lender from the Administrative Agent or any of its Affiliates (whether as a payment, prepayment or repayment of principal, interest, fees or otherwise; individually and collectively, a "Payment") were erroneously transmitted to such Lender (whether or not known to such Lender), and demands the return of such Payment (or a portion thereof), such Lender shall promptly, but in no event later than one Business Day thereafter, return to the Administrative Agent the amount of any such Payment (or portion thereof) as to which such a demand was made in same day funds, together with interest thereon in respect of each day from and including the date such Payment (or portion thereof) was received by such Lender to the date such amount is repaid to the Administrative Agent at the greater of the NYFRB Rate and a rate determined by the Administrative Agent in accordance with banking industry rules on interbank compensation from time to time in effect, and (y) to the extent permitted by applicable law, such Lender shall not assert, and hereby waives, as to the Administrative Agent, any claim, counterclaim, defense or right of set-off or recoupment with respect to any demand, claim or counterclaim by the Administrative Agent for the return of any Payments received, including without limitation any defense based on "discharge for value" or any similar doctrine. A notice of the Administrative Agent to any Lender under this Section 8.06(c) shall be conclusive, absent manifest error.

(ii) Each Lender hereby further agrees that if it receives a Payment from the Administrative Agent or any of its Affiliates (x) that is in a different amount than, or on a different date from, that specified in a notice of payment sent by the Administrative Agent (or any of its Affiliates) with respect to such Payment (a "Payment Notice") or (y) that was not preceded or accompanied by a Payment Notice, it shall be on notice, in each such case, that an error has been made with respect to such Payment. Each Lender agrees that, in each such case, or if it otherwise becomes aware a Payment (or portion thereof) may have been sent in error, such Lender shall promptly notify the Administrative Agent of such occurrence and, upon demand from the Administrative Agent, it shall promptly, but in no event later than one Business Day thereafter, return to the Administrative Agent the amount of any such Payment (or portion thereof) as to which such a demand was made in same day funds, together with interest thereon in respect of each day from and including the date such Payment (or portion thereof) was received by such Lender to the date such amount is repaid to the Administrative Agent at the greater of the NYFRB Rate and a rate determined by the Administrative Agent in accordance with banking industry rules on interbank compensation from time to time in effect.

(iii) The Borrower hereby agrees that (x) in the event an erroneous Payment (or portion thereof) are not recovered from any Lender that has received such Payment (or portion thereof) for any reason, the Administrative Agent shall be subrogated to all the rights of such Lender with respect to such amount and (y) an erroneous Payment shall not pay, prepay, repay, discharge or otherwise satisfy any Obligations owed by the Borrower.

(iv) Each party's obligations under this Section 8.06(c) shall survive the resignation or replacement of the Administrative Agent or any transfer of rights or obligations by, or the replacement of, a Lender, the termination of the Commitments or the repayment, satisfaction or discharge of all Obligations under any Loan Document.

SECTION 8.07 Certain ERISA Matters. (a) Each Lender (x) represents and warrants, as of the date such Person became a Lender party hereto, to, and (y) covenants, from the date such Person became a Lender party hereto to the date such Person ceases being a Lender party hereto, for the benefit of, the Administrative Agent, and each Arranger and their respective Affiliates, and not, for the avoidance of doubt, to or for the benefit of the Borrower, that at least one of the following is and will be true:

(i) such Lender is not using "plan assets" (within the meaning of the Plan Asset Regulations) of one or more Benefit Plans in connection with the Loans, the Letters of Credit or the Commitments,

(ii) the transaction exemption set forth in one or more PTEs, such as PTE 84-14 (a class exemption for certain transactions determined by independent qualified professional asset managers), PTE 95-60 (a class exemption for certain transactions involving insurance company general accounts), PTE 90-1 (a class exemption for certain transactions involving insurance company pooled separate accounts), PTE 91-38 (a class exemption for certain transactions involving bank collective investment funds) or PTE 96-23 (a class exemption for certain transactions determined by in-house asset managers), is applicable with respect to such Lender's entrance into, participation in, administration of and performance of the Loans, the Letters of Credit, the Commitments and this Agreement, and the conditions for exemptive relief thereunder are and will continue to be satisfied in connection therewith,

(iii) (A) such Lender is an investment fund managed by a "Qualified Professional Asset Manager" (within the meaning of Part VI of PTE 84-14), (B) such Qualified Professional Asset Manager made the investment decision on behalf of such Lender to enter into, participate in, administer and perform the Loans, the Letters of Credit, the Commitments and this Agreement, (C) the entrance into, participation in, administration of and performance of the Loans, the Letters of Credit, the Commitments and this Agreement satisfies the requirements of sub-sections (b) through (g) of Part I of PTE 84-14 and (D) to the best knowledge of such Lender, the requirements of subsection (a) of Part I of PTE 84-14 are satisfied with respect to such Lender's entrance into, participation in, administration of and performance of the Loans, the Letters of Credit, the Commitments and this Agreement, or

(iv) such other representation, warranty and covenant as may be agreed in writing between the Administrative Agent, in its sole discretion, and such Lender.

(b) In addition, unless either (1) sub-clause (i) in the immediately preceding clause (a) is true with respect to a Lender or (2) a Lender has provided another representation, warranty and covenant in accordance with sub-clause (iv) in the immediately preceding clause (a), such Lender further (x) represents and warrants, as of the date such Person became a Lender party hereto, to, and (y) covenants, from the date such Person became a Lender party hereto to the date such Person ceases being a Lender party hereto, for the benefit of, the Administrative Agent, each Arranger and their respective Affiliates, and not, for the avoidance of doubt, to or for the benefit of the Borrower, that none of the Administrative Agent, or any Arranger, any Co-Syndication Agent, the Sustainability Structuring Agent or any of their Affiliates is a fiduciary with respect to the assets of such Lender involved in such Lender's entrance into, participation in, administration of and performance of the Loans, the Letters of Credit, the Commitments and this Agreement (including in connection with the reservation or exercise of any rights by the Administrative Agent under this Agreement, any Loan Document or any documents related hereto or thereto).

(c) The Administrative Agent, and each Arranger hereby informs the Lenders that each such Person is not undertaking to provide impartial investment advice, or to give advice in a fiduciary capacity, in connection with the transactions contemplated hereby, and that such Person has a financial interest in the transactions contemplated hereby in that such Person or an Affiliate thereof (i) may receive interest or other payments with respect to the Loans, the Letters of Credit, the Commitments and this Agreement, (ii) may recognize a gain if it extended the Loans, the Letters of Credit or the Commitments for an amount less than the amount being paid for an interest in the Loans, the Letters of Credit or the Commitments by such Lender or (iii) may receive fees or other payments in connection with the transactions contemplated hereby, the Loan Documents or otherwise, including structuring fees, commitment fees, arrangement fees, facility fees, upfront fees, underwriting fees, ticking fees, agency fees, administrative agent or collateral agent fees, utilization fees, minimum usage fees, letter of credit fees, fronting fees, deal-away or alternate transaction fees, amendment fees, processing fees, term out premiums, banker's acceptance fees, breakage or other early termination fees or fees similar to the foregoing.

SECTION 8.08 Certain Sustainability Matters. Each party hereto hereby agrees that neither the Administrative Agent nor the Sustainability Structuring Agent shall have any responsibility for (or liability in respect of) reviewing, auditing or otherwise evaluating any calculation by the Borrower of any Sustainability Facility Fee Adjustment or any Sustainability Rate Adjustment (or any of the data or computations that are part of or related to any such calculation) set forth in any Pricing Certificate (and the Administrative Agent may rely conclusively on any such certificate, without further inquiry).

ARTICLE IX

Miscellaneous

SECTION 9.01 Notices. (a) Except in the case of notices and other communications expressly permitted to be given by telephone (and subject to paragraph (b) below), all notices and other communications provided for herein shall be in writing and shall be delivered by hand or overnight courier service, mailed by certified or registered mail or sent by telecopy, as follows:

(i) if to the Borrower, to it at 250 SW Taylor Street, Portland, OR 97204, Attention of Brody J. Wilson, Vice President, Treasurer, Chief Accounting Officer and Controller (Telecopy No. (503) 220-2584; Telephone No. (503) 610-7176; Email Address: brody.wilson@nwnatural.com);

(ii) if to the Administrative Agent, to JPMorgan Chase Bank, N.A., 131 S Dearborn St, Floor 04, Chicago, IL 60603-5506, Attention of Kathryn V Tyler (Telecopy No. (844) 490-5663, Telephone No. (312) 954-0447; Email Address: katy.tyler@chase.com);

(iii) if to the Issuing Banks,

(A) in the case of JPMorgan Chase Bank, N.A, to it at JPMorgan Chase Bank, N.A., 8181 Communications Pkwy, Building B, 6th Floor, Plano, TX 75024, Attention of Hamza Tariq (Telephone No. (972) 324-2325; Email Address: hamza.tariq@jpmorgan.com);

(B) if to Bank of America, N.A. to it at Bank of America, N.A., Commercial Banking Credit Products, OR1-129-17-01
121, SW Morrison St., Suite 1700, Portland, OR 97204, Attention of Daryl K. Hogge (Telecopy No. (312) 453-5325; Telephone No. (503) 795-6469; Email Address: daryl.k.hogge@baml.com);

(C) if to U.S. Bank National Association to it at U.S. Bank National Association, Corporate & Commercial Banking, 209 S. LaSalle St., Chicago, IL 60604 , MK-IL-RY3S, Attention of John M. Eyerman (Telephone No. (312) 325-2032; Email Address: john.eyerman@usbank.com); and

(D) if to Wells Fargo Bank, National Association to it at Wells Fargo Bank, National Association, Wells Fargo Corporate Banking, 90 S. Seventh Street, 15th Floor MAC: N9305-15G, Minneapolis, MN 55402 Attention of Gregory R. Gredvig (Telecopy No. (612) 316-0506; Telephone No. (612) 667-4832; Email Address: gregory.r.gredvig@wellsfargo.com); and

(iv) if to any other Lender, to it at its address (or telecopy number) set forth in its Administrative Questionnaire.

Notices sent by hand or overnight courier service, or mailed by certified or registered mail, shall be deemed to have been given when received; notices sent by facsimile shall be deemed to have been given when sent (except that, if not given during normal business hours for the recipient, shall be deemed to have been given at the opening of business on the next Business Day for the recipient). Notices delivered through Approved Electronic Platforms, to the extent provided in paragraph (b) below, shall be effective as provided in said paragraph (b).

(b) Notices and other communications to the Lenders and the Issuing Banks hereunder may be delivered or furnished by using Approved Electronic Platforms pursuant to procedures approved by the Administrative Agent; provided that the foregoing shall not apply to notices pursuant to Article II unless otherwise agreed by the Administrative Agent and the applicable Lender. The Administrative Agent or the Borrower may, in its discretion, agree to accept notices and other communications to it hereunder by electronic communications pursuant to procedures approved by it; provided that approval of such procedures may be limited to particular notices or communications.

Unless the Administrative Agent otherwise prescribes, (i) notices and other communications sent to an e-mail address shall be deemed received upon the sender's receipt of an acknowledgement from the intended recipient (such as by the "return receipt requested" function, as available, return e-mail or other written acknowledgement), and (ii) notices or communications posted to an Internet or intranet website shall be deemed received upon the deemed receipt by the intended recipient, at its e-mail address as described in the foregoing clause (i), of notification that such notice or communication is available and identifying the website address therefor; provided that, for both clauses (i) and (ii) above, if such notice, email or other communication is not sent during the normal business hours of the recipient, such notice or communication shall be deemed to have been sent at the opening of business on the next Business Day for the recipient.

(c) Any party hereto may change its address or telecopy number for notices and other communications hereunder by written notice to the other parties hereto.

SECTION 9.02 Waivers; Amendments. (a) No failure or delay by the Administrative Agent, any Issuing Bank or any Lender in exercising any right or power hereunder or under any other Loan Document shall operate as a waiver thereof, nor shall any single or partial exercise of any such right or power, or any abandonment or discontinuance of steps to enforce such a right or power, preclude any other or further exercise thereof or the exercise of any other right or power. The rights and remedies of the Administrative Agent, the Issuing Banks and the Lenders hereunder and under the other Loan Documents are cumulative and are not exclusive of any rights or remedies that they would otherwise have. No waiver of any provision of this Agreement or consent to any departure by the Borrower therefrom shall in any event be effective unless the same shall be permitted by paragraph (b) of this Section, and then such waiver or consent shall be effective only in the specific instance and for the purpose for which given. Without limiting the generality of the foregoing, the making of a Loan or issuance of a Letter of Credit shall not be construed as a waiver of any Default, regardless of whether the Administrative Agent, any Lender or any Issuing Bank may have had notice or knowledge of such Default at the time.

(b) Subject to Section 2.14(b), (c) and (d), and clauses (c) and (d) below, neither this Agreement nor any provision hereof may be waived, amended or modified except pursuant to an agreement or agreements in writing entered into by the Borrower and the Required Lenders or by the Borrower and the Administrative Agent with the consent of the Required Lenders; provided that no such agreement shall (i) increase the Commitment of any Lender without the written consent of such Lender, (ii) reduce the principal amount of any Loan or LC Disbursement or reduce the rate of interest thereon, or reduce any fees payable hereunder, without the written consent of each Lender directly affected thereby, (iii) postpone the scheduled date of payment of the principal amount of any Loan or LC Disbursement, or any interest thereon, or any fees payable hereunder, or reduce the amount of, waive or excuse any such payment, or postpone the scheduled date of expiration of any Commitment, without the written consent of each Lender directly affected thereby, (iv) change Section 2.09(c) or Section 2.18(b) or (d) in a manner that would alter the ratable reduction of Commitments or pro rata sharing of payments required thereby, without the written consent of each Lender, (v) change the payment waterfall provisions of Section 2.21(b) or 7.02 without the written consent of each Lender or (vi) change any of the provisions of this Section or the definition of "Required Lenders" or any other provision hereof specifying the number or percentage of Lenders required to waive, amend or modify any rights hereunder or make any determination or grant any consent hereunder, without the written consent of each Lender (it being understood that, solely with the consent of the parties prescribed by Section 2.20 to be parties to an

Incremental Term Loan Amendment, Incremental Term Loans may be included in the determination of Required Lenders on substantially the same basis as the Commitments and the Revolving Loans are included on the Restatement Effective Date); provided further that no such agreement shall amend, modify or otherwise affect the rights or duties of the Administrative Agent or any Issuing Bank hereunder without the prior written consent of the Administrative Agent or such Issuing Bank, as the case may be (it being understood that any change to Section 2.21 shall require the consent of the Administrative Agent and the Issuing Banks); provided further, that no such agreement shall amend or modify the provisions of Section 2.06 or any letter of credit application and any bilateral agreement between the Borrower and any Issuing Bank regarding such Issuing Bank's Letter of Credit Commitment or the respective rights and obligations between the Borrower and such Issuing Bank in connection with the issuance of Letters of Credit without the prior written consent of the Administrative Agent and such Issuing Bank, respectively. Notwithstanding the foregoing, no consent with respect to any amendment, waiver or other modification of this Agreement shall be required of any Defaulting Lender, except with respect to any amendment, waiver or other modification referred to in clause (i), (ii) or (iii) of the first proviso of this paragraph and then only in the event such Defaulting Lender shall be directly affected by such amendment, waiver or other modification.

(c) Notwithstanding the foregoing, this Agreement and any other Loan Document may be amended (or amended and restated) with the written consent of the Required Lenders, the Administrative Agent and the Borrower (x) to add one or more credit facilities (in addition to the Incremental Term Loans pursuant to an Incremental Term Loan Amendment) to this Agreement and to permit extensions of credit from time to time outstanding thereunder and the accrued interest and fees in respect thereof to share ratably in the benefits of this Agreement and the other Loan Documents with the Revolving Loans, Incremental Term Loans and the accrued interest and fees in respect thereof and (y) to include appropriately the Lenders holding such credit facilities in any determination of the Required Lenders and Lenders.

(d) If the Administrative Agent and the Borrower acting together identify any ambiguity, omission, mistake, typographical error or other defect in any provision of this Agreement or any other Loan Document, then the Administrative Agent and the Borrower shall be permitted to amend, modify or supplement such provision to cure such ambiguity, omission, mistake, typographical error or other defect, and such amendment shall become effective without any further action or consent of any other party to this Agreement.

SECTION 9.03 Expenses; Limitation of Liability; Indemnity; Etc.

(a) Expenses. The Borrower shall pay (i) all reasonable out-of-pocket expenses incurred by the Administrative Agent, the Co-Syndication Agents, the Sustainability Structuring Agent, the Arrangers and their respective Affiliates, including the reasonable fees, charges and disbursements of counsel and other advisors and professionals for such Persons, in connection with the syndication and distribution (including, without limitation, via the internet or through a service such as Intralinks) of the credit facilities provided for herein, the investigation, preparation, negotiation, documentation, collection and administration of this Agreement and the other Loan Documents or any amendments, modifications or waivers of the provisions hereof or thereof (whether or not the transactions contemplated hereby or thereby shall be consummated), (ii) all reasonable out-of-pocket expenses incurred by any Issuing Bank in connection with the issuance, amendment, renewal or extension of any Letter of Credit or any demand for payment thereunder and (iii) all out-of-pocket expenses incurred by the Administrative Agent, the Co-Syndication Agents, the Sustainability Structuring Agent, any Arranger, any Issuing Bank or any Lender, including the fees, charges and disbursements of any counsel for the Administrative Agent, the Co-Syndication Agents, the Sustainability Structuring Agent, any Arranger, any Issuing Bank or any Lender, in connection with the enforcement or protection of its rights in connection with this Agreement and any other Loan Document, including its rights under this Section, or in connection with the Loans made or Letters of Credit issued hereunder, including all such out-of-pocket expenses incurred during any workout, restructuring or negotiations in respect of such Loans or Letters of Credit.

(b) Indemnity. The Borrower shall indemnify the Administrative Agent, the Co-Syndication Agents, the Sustainability Structuring Agent, each Arranger, any Issuing Bank and each Lender, and each Related Party of any of the foregoing Persons (each such Person being called an

"Indemnitee") against, and hold each Indemnitee harmless from, any and all Liabilities and related expenses, including the fees, charges and disbursements of any counsel for any Indemnitee, incurred by or asserted against any Indemnitee arising out of, in connection with, or as a result of (i) the execution or delivery of this Agreement, any other Loan Document or any agreement or instrument contemplated hereby or thereby, the performance by the parties hereto of their respective obligations hereunder or thereunder or the consummation of the Transactions or any other transactions contemplated hereby, (ii) any Loan or Letter of Credit or the use of the proceeds therefrom (including any refusal by any Issuing Bank to honor a demand for payment under a Letter of Credit if the documents presented in connection with such demand do not strictly comply with the terms of such Letter of Credit), (iii) any actual or alleged presence or release of Hazardous Materials on or from any property owned or operated by the Borrower or any of its Subsidiaries, or any Environmental Liability related in any way to the Borrower or any of its Subsidiaries, or (iv) any actual or prospective Proceeding relating to any of the foregoing, whether or not such Proceeding is brought by the Borrower or its respective equity holders, Affiliates, creditors or any other third Person and whether based on contract, tort or any other theory and regardless of whether any Indemnitee is a party thereto; provided that such indemnity shall not, as to any Indemnitee, be available to the extent that such Liabilities or related expenses (A) result from a claim brought by the Borrower or any of its Subsidiaries against such Indemnitee for material breach of such Indemnitee's or any of its Related Parties' obligations under any Loan Document if the Borrower or such Subsidiary has obtained a final and nonappealable judgment in its favor on such claim as determined by a court of competent jurisdiction or (B) are determined by a court of competent jurisdiction by final and nonappealable judgment to have resulted from the gross negligence or willful misconduct of such Indemnitee. This Section 9.03(b) shall not apply with respect to Taxes other than any Taxes that represent losses, claims or damages arising from any non-Tax claim.

(c) Lender Reimbursement. Each Lender severally agrees to pay any amount required to be paid by the Borrower under paragraph (a) or (b) of this Section 9.03 to the Administrative Agent, the Co-Syndication Agents, the Sustainability Structuring Agent the Arrangers and the Issuing Banks, and each Related Party of any of the foregoing Persons (each, an "Agent-Related Person") (to the extent not reimbursed by the Borrower and without limiting the obligation of the Borrower to do so), ratably according to their respective Applicable Percentage in effect on the date on which such payment is sought under this Section (or, if such payment is sought after the date upon which the Commitments shall have terminated and the Loans shall have been paid in full, ratably in accordance with such Applicable Percentage immediately prior to such date), and agrees to indemnify and hold each Agent-Related Person harmless from and against any and all Liabilities and related expenses, including the fees, charges and disbursements of any kind whatsoever that may at any time (whether before or after the payment of the Loans) be imposed on, incurred by or asserted against such Agent-Related Person in any way relating to or arising out of the Commitments, this Agreement, any of the other Loan Documents or any documents contemplated by or referred to herein or therein or the transactions contemplated hereby or thereby or any action taken or omitted by such Agent-Related Person under or in connection with any of the foregoing; provided that the unreimbursed expense or Liability or related expense, as the case may be, was incurred by or asserted against such Agent-Related Person in its capacity as such; provided further that no Lender shall be liable for the payment of any portion of such Liabilities, costs, expenses or disbursements that are found by a final and nonappealable decision of a court of competent jurisdiction to have resulted from such Agent-Related Person's gross negligence or willful misconduct. The agreements in this Section shall survive the termination of this Agreement and the payment of the Loans and all other amounts payable hereunder.

(d) Limitation of Liability. To the extent permitted by applicable law, (i) the Borrower shall not assert, and hereby waives, any claim against the Administrative Agent, any Arranger, any Co-Syndication Agent, the Sustainability Structuring Agent, any Issuing Bank and any Lender, and any Related Party of any of the foregoing Persons (each such Person being called a "Lender-Related Person") for any Liabilities arising from the use by others of information or other materials obtained through telecommunications, electronic or other information transmission systems (including the Internet), and (ii) no party hereto shall assert, and each such party hereby waives, any claim against any other party hereto, on any theory of liability, for special, indirect, consequential or punitive damages (as opposed to direct or actual damages) arising out of, in connection with, or as a result of, this Agreement, any other Loan Document or any agreement or instrument contemplated hereby or thereby, the Transactions, any Loan or Letter of Credit or the use of the proceeds thereof; provided that, nothing in this clause (d)(ii) shall relieve the Borrower of any obligation it may have to indemnify an Indemnitee against special, indirect, consequential or punitive damages asserted against such Indemnitee by a third party.

(e) Payments. All amounts due under this Section shall be payable promptly after written demand therefor.

SECTION 9.04 Successors and Assigns. (a) The provisions of this Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns permitted hereby (including any Affiliate of any Issuing Bank that issues any Letter of Credit), except that (i) the Borrower may not assign or otherwise transfer any of its rights or obligations hereunder without the prior written consent of each Lender (and any attempted assignment or transfer by the Borrower without such consent shall be null and void) and (ii) no Lender may assign or otherwise transfer its rights or obligations hereunder except in accordance with this Section. Nothing in this Agreement, expressed or implied, shall be construed to confer upon any Person (other than the parties hereto, their respective successors and assigns permitted hereby (including any Affiliate of any Issuing Bank that issues any Letter of Credit), Participants (to the extent provided in paragraph (c) of this Section) and, to the extent expressly contemplated hereby, the Related Parties of each of the Administrative Agent, the Issuing Banks and the Lenders) any legal or equitable right, remedy or claim under or by reason of this Agreement.

(b) (i) Subject to the conditions set forth in paragraph (b)(ii) below, any Lender may assign to one or more Persons (other than an Ineligible Institution) all or a portion of its rights and obligations under this Agreement (including all or a portion of its Commitment, participations in Letters of Credit and the Loans at the time owing to it) with the prior written consent (such consent not to be unreasonably withheld) of:

(A) the Borrower (provided that the Borrower shall be deemed to have consented to any such assignment unless it shall object thereto by written notice to the Administrative Agent within ten (10) Business Days after having received notice thereof); provided, further, that no consent of the Borrower shall be required for an assignment to a Lender, an Affiliate of a Lender, an Approved Fund or, if an Event of Default has occurred and is continuing, any other assignee;

(B) the Administrative Agent; provided, that no consent of the Administrative Agent shall be required for an assignment of any Commitment to an assignee that is a Lender (other than a Defaulting Lender) with a Commitment immediately prior to giving effect to such assignment; and

(C) the Issuing Banks.

(ii) Assignments shall be subject to the following additional conditions:

(A) except in the case of an assignment to a Lender or an Affiliate of a Lender or an Approved Fund or an assignment of the entire remaining amount of the assigning Lender's Commitment or Loans, the amount of the Commitment or Loans of the assigning Lender subject to each such assignment (determined as of the date the Assignment and Assumption with respect to such assignment is delivered to the Administrative Agent) shall not be less than $5,000,000 unless each of the Borrower and the Administrative Agent otherwise consent to a lesser amount, provided that no such consent of the Borrower shall be required if an Event of Default has occurred and is continuing;

(B) each partial assignment shall be made as an assignment of a proportionate part of all the assigning Lender's rights and obligations under this Agreement;

(C) the parties to each assignment shall execute and deliver to the Administrative Agent (x) an Assignment and Assumption or (y) to the extent applicable, an agreement incorporating an Assignment and Assumption by reference pursuant to an Approved Electronic Platform as to which the Administrative Agent and the parties to the Assignment and Assumption are participants, together with a processing and recordation fee of $3,500, such fee to be paid by either the assigning Lender or the assignee Lender or shared between such Lenders; and

(D) the assignee, if it shall not be a Lender, shall deliver to the Administrative Agent an Administrative Questionnaire in which the assignee designates one or more credit contacts to whom all syndicate-level information (which may contain material non-public information about the Borrower and its Affiliates and their Related Parties or their respective securities) will be made available and who may receive such information in accordance with the assignee's compliance procedures and applicable laws, including Federal and state securities laws.

For the purposes of this Section 9.04(b), the terms "Approved Fund" and "Ineligible Institution" have the following meanings:

"Approved Fund" means any Person (other than a natural person) that is engaged in making, purchasing, holding or investing in bank loans and similar extensions of credit in the ordinary course of its business and that is administered or managed by (a) a Lender, (b) an Affiliate of a Lender or (c) an entity or an Affiliate of an entity that administers or manages a Lender.

"Ineligible Institution" means (a) a natural person, (b) a Defaulting Lender or its Lender Parent, (c) a holding company, investment vehicle or trust for, or owned and operated for the primary benefit of, a natural person or relative(s) thereof or (d) the Borrower or any of its Affiliates; provided that, with respect to clause (c), such holding company, investment vehicle or trust shall not constitute an Ineligible Institution if it (x) has not been established for the primary purpose of acquiring any Loans or Commitments, (y) is managed by a professional advisor, who is not such natural person or a relative thereof, having significant experience in the business of making or purchasing commercial loans, and (z) has assets greater than $25,000,000 and a significant part of its activities consist of making or purchasing commercial loans and similar extensions of credit in the ordinary course of its business.

(iii) Subject to acceptance and recording thereof pursuant to paragraph (b)(iv) of this Section, from and after the effective date specified in each Assignment and Assumption the assignee thereunder shall be a party hereto and, to the extent of the interest assigned by such Assignment and Assumption, have the rights and obligations of a Lender under this Agreement, and the assigning Lender thereunder shall, to the extent of the interest assigned by such Assignment and Assumption, be released from its obligations under this Agreement (and, in the case of an Assignment and Assumption covering all of the assigning Lender's rights and obligations under this Agreement, such Lender shall cease to be a party hereto but shall continue to be entitled to the benefits of Sections 2.15, 2.16, 2.17 and 9.03). Any assignment or transfer by a Lender of rights or obligations under this Agreement that does not comply with this Section 9.04 shall be treated for purposes of this Agreement as a sale by such Lender of a participation in such rights and obligations in accordance with paragraph (c) of this Section.

(iv) The Administrative Agent, acting for this purpose as a non-fiduciary agent of the Borrower, shall maintain at one of its offices a copy of each Assignment and Assumption delivered to it and a register for the recordation of the names and addresses of the Lenders, and the Commitment of, and principal amount (and stated interest) of the Loans and LC Disbursements owing to, each Lender pursuant to the terms hereof from time to time (the "Register"). The entries in the Register shall be conclusive, and the Borrower, the Administrative Agent, the Issuing Banks and the Lenders shall treat each Person whose name is recorded in the Register pursuant to the terms hereof as a Lender hereunder for all purposes of this Agreement, notwithstanding notice to the contrary. The Register shall be available for inspection by the Borrower, any Issuing Bank and any Lender, at any reasonable time and from time to time upon reasonable prior notice.

(v) Upon its receipt of (x) a duly completed Assignment and Assumption executed by an assigning Lender and an assignee or (y) to the extent applicable, an agreement incorporating an Assignment and Assumption by reference pursuant to an Approved Electronic Platform as to which the Administrative Agent and the parties to the Assignment and Assumption are participants, the assignee's completed Administrative Questionnaire (unless the assignee shall already be a Lender hereunder), the processing and recordation fee referred to in paragraph (b) of this Section and any written consent to such assignment required by paragraph (b) of this Section, the Administrative Agent shall accept such Assignment and Assumption and record the information contained therein in the Register; provided that if either the assigning Lender or the assignee shall have failed to make any payment required to be made by it pursuant to Section 2.06(d) or (e), 2.07(b), 2.18(e) or 9.03(c), the Administrative Agent shall have no obligation to accept such Assignment and Assumption and record the information therein in the Register unless and until such payment shall have been made in full, together with all accrued interest thereon. No assignment shall be effective for purposes of this Agreement unless it has been recorded in the Register as provided in this paragraph.

(c) Any Lender may, without the consent of, or notice to, the Borrower, the Administrative Agent or the Issuing Banks, sell participations to one or more banks or other entities (a "Participant"), other than an Ineligible Institution, in all or a portion of such Lender's rights and/or obligations under this Agreement (including all or a portion of its Commitment and/or the Loans owing to it); provided that (A) such Lender's obligations under this Agreement shall remain unchanged; (B) such Lender shall remain solely responsible to the other parties hereto for the performance of such obligations; and (C) the Borrower, the Administrative Agent, the Issuing Banks and the other Lenders shall continue to deal solely and directly with such Lender in connection with such Lender's rights and obligations under this Agreement. Any agreement or instrument pursuant to which a Lender sells such a participation shall provide that such Lender shall retain the sole right to enforce this Agreement and to approve any amendment, modification or waiver of any provision of this Agreement; provided that such agreement or instrument may provide that such Lender will not, without the consent of the Participant, agree to any amendment, modification or waiver described in the first proviso to Section 9.02(b) that affects such Participant. The Borrower agrees that each Participant shall be entitled to the benefits of Sections 2.15, 2.16 and 2.17 (subject to the requirements and limitations therein, including the requirements under Section 2.17(f) (it being understood that the documentation required under Section 2.17(f) shall be delivered to the participating Lender)) to the same extent as if it were a Lender and had acquired its interest by assignment pursuant to paragraph (b) of this Section; provided that such Participant (A) agrees to be subject to the provisions of Sections 2.18 and 2.19 as if it were an assignee under paragraph (b) of this Section; and (B) shall not be entitled to receive any greater payment under Sections 2.15 or 2.17, with respect to any participation, than its participating Lender would have been entitled to receive, except to the extent such entitlement to receive a greater payment results from a Change in Law that occurs after the Participant acquired the applicable participation. Each Lender that sells a participation agrees, at the Borrower's request and expense, to use reasonable efforts to cooperate with the Borrower to effectuate the provisions of Section 2.19(b) with respect to any Participant. To the extent permitted by law, each Participant also shall be entitled to the benefits of Section 9.08 as though it were a Lender, provided that such Participant agrees to be subject to Section 2.18(c) as though it were a Lender. Each Lender that sells a participation shall, acting solely for this purpose as a non-fiduciary agent of the Borrower, maintain a register on which it enters the name and address of each Participant and the principal amounts (and stated interest) of each Participant's interest in the Loans or other obligations under the Loan Documents (the "Participant Register"); provided that no Lender shall have any obligation to disclose all or any portion of the Participant Register (including the identity of any Participant or any information relating to a Participant's interest in any Commitments, Loans, Letters of Credit or its other obligations under any Loan Document) to any Person except to the extent that such disclosure is necessary to establish that such Commitment, Loan, Letter of Credit or other obligation is in registered form under Section 5f.103-1(c) of the United States Treasury Regulations. The entries in the Participant Register shall be conclusive absent manifest error, and such Lender shall treat each Person whose name is recorded in the Participant Register as the owner of such participation for all purposes of this Agreement notwithstanding any notice to the contrary. For the avoidance of doubt, the Administrative Agent (in its capacity as Administrative Agent) shall have no responsibility for maintaining a Participant Register.

(d) Any Lender may at any time pledge or assign a security interest in all or any portion of its rights under this Agreement to secure obligations of such Lender, including any pledge or assignment to secure obligations to a Federal Reserve Bank, and this Section shall not apply to any such pledge or assignment of a security interest; provided that no such pledge or assignment of a security interest shall release a Lender from any of its obligations hereunder or substitute any such pledgee or assignee for such Lender as a party hereto.

SECTION 9.05 Survival. All covenants, agreements, representations and warranties made by the Borrower in the Loan Documents and in the certificates or other instruments delivered in connection with or pursuant to this Agreement or any other Loan Document shall be considered to have been relied upon by the other parties hereto and shall survive the execution and delivery of the Loan Documents and the making of any Loans and issuance of any Letters of Credit, regardless of any investigation made by any such other party or on its behalf and notwithstanding that the Administrative Agent, any Issuing Bank or any Lender may have had notice or knowledge of any Default or incorrect representation or warranty at the time any credit is extended hereunder, and shall continue in full force and effect as long as the principal of or any accrued interest on any Loan or any fee or any other amount payable under this Agreement or any other Loan Document is outstanding and unpaid or any Letter of Credit is outstanding and so long as the Commitments have not expired or terminated. The provisions of Sections 2.15, 2.16, 2.17 and 9.03 and Article VIII shall survive and remain in full force and effect regardless of the consummation of the transactions contemplated hereby, the repayment of the Loans, the expiration or termination of the Letters of Credit and the Commitments or the termination of this Agreement or any other Loan Document or any provision hereof or thereof.

SECTION 9.06 Counterparts; Integration; Effectiveness; Electronic Execution. (a) This Agreement may be executed in counterparts (and by different parties hereto on different counterparts), each of which shall constitute an original, but all of which when taken together shall constitute a single contract. This Agreement, the other Loan Documents and any separate letter agreements with respect to (i) fees payable to the Administrative Agent and (ii) the reductions of the Letter of Credit Commitment of any Issuing Bank constitute the entire contract among the parties relating to the subject matter hereof and supersede any and all previous agreements and understandings, oral or written, relating to the subject matter hereof. Except as provided in Section 4.01, this Agreement shall become effective when it shall have been executed by the Administrative Agent and when the Administrative Agent shall have received counterparts hereof which, when taken together, bear the signatures of each of the other parties hereto, and thereafter shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns.

(b) Delivery of an executed counterpart of a signature page of (x) this Agreement, (y) any other Loan Document and/or (z) any document, amendment, approval, consent, information, notice (including, for the avoidance of doubt, any notice delivered pursuant to Section 9.01), certificate, request, statement, disclosure or authorization related to this Agreement, any other Loan Document and/or the transactions contemplated hereby and/or thereby (each an "Ancillary Document") that is an Electronic Signature transmitted by telecopy, emailed pdf. or any other electronic means that reproduces an image of an actual executed signature page shall be effective as delivery of a manually executed counterpart of this Agreement, such other Loan Document or such Ancillary Document, as applicable. The words "execution," "signed," "signature," "delivery," and words of like import in or relating to this Agreement, any other Loan Document and/or any Ancillary Document shall be deemed to include Electronic Signatures, deliveries or the keeping of records in any electronic form (including deliveries by telecopy, emailed pdf. or any other electronic means that reproduces an image of an actual executed signature page), each of which shall be of the same legal effect, validity or enforceability as a manually executed signature, physical delivery thereof or the use of a paper-based recordkeeping system, as the case may be; provided that nothing herein shall require the Administrative Agent to accept Electronic Signatures in any form or format without its prior written consent and pursuant to procedures approved by it; provided, further, without limiting the foregoing, (i) to the extent the Administrative Agent has agreed to accept any Electronic Signature, the Administrative Agent and each of the Lenders shall be entitled to rely on such Electronic Signature purportedly given by or on behalf of the Borrower without further verification thereof and without any obligation to review the appearance or form of any such Electronic signature and (ii) upon the request of the Administrative Agent or any Lender, any Electronic Signature shall be promptly followed by a manually executed counterpart. Without limiting the generality of the foregoing, the Borrower hereby (i) agrees that, for all purposes, including without limitation, in connection with any workout, restructuring, enforcement of remedies, bankruptcy proceedings or litigation among the Administrative Agent, the Lenders and the Borrower, Electronic Signatures transmitted by telecopy, emailed pdf. or any other electronic means that reproduces an image of an actual executed signature page and/or any electronic images of this Agreement, any other Loan Document and/or any Ancillary Document shall have the same legal effect, validity and enforceability as any paper original, (ii) the Administrative Agent and each of the Lenders may, at its option, create one or more copies of this Agreement, any other Loan Document and/or any Ancillary Document in the form of an imaged electronic record in any format, which shall be deemed created in the ordinary course of such Person's business, and destroy the original paper document (and all such electronic records shall be considered an original for all purposes and shall have the same legal effect, validity and enforceability as a paper record), (iii) waives any argument, defense or right to contest the legal effect, validity or enforceability of this Agreement, any other Loan Document and/or any Ancillary Document based solely on the lack of paper original copies of this Agreement, such other Loan Document and/or such Ancillary Document, respectively, including with respect to any signature pages thereto and (iv) waives any claim against any Lender-Related Person for any Liabilities arising solely from the Administrative Agent's and/or any Lender's reliance on or use of Electronic Signatures and/or transmissions by telecopy, emailed pdf. or any other electronic means that reproduces an image of an actual executed signature page, including any Liabilities arising as a result of the failure of the Borrower to use any available security measures in connection with the execution, delivery or transmission of any Electronic Signature.

SECTION 9.07 Severability. Any provision of any Loan Document held to be invalid, illegal or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such invalidity, illegality or unenforceability without affecting the validity, legality and enforceability of the remaining provisions thereof; and the invalidity of a particular provision in a particular jurisdiction shall not invalidate such provision in any other jurisdiction.

SECTION 9.08 Right of Setoff. If an Event of Default shall have occurred and be continuing, each Lender, each Issuing Bank, and each of their respective Affiliates is hereby authorized at any time and from time to time, to the fullest extent permitted by law, to set off and apply any and all deposits (general or special, time or demand, provisional or final and in whatever currency denominated) at any time held, and other obligations at any time owing, by such Lender, such Issuing Bank or any such Affiliate, to or for the credit or the account of the Borrower against any and all of the Obligations now or hereafter existing under this Agreement or any other Loan Document to such Lender or such Issuing Bank or their respective Affiliates, irrespective of whether or not such Lender, Issuing Bank or Affiliate shall have made any demand under this Agreement or any other Loan Document and although such obligations may be contingent or unmatured or are owed to a branch office or Affiliate of such Lender or such Issuing Bank different from the branch office or Affiliate holding such deposit or obligated on such indebtedness; provided that in the event that any Defaulting Lender shall exercise any such right of setoff, (x) all amounts so set off shall be paid over immediately to the Administrative Agent for further application in accordance with the provisions of Section 2.21 and, pending such payment, shall be segregated by such Defaulting Lender from its other funds and deemed held in trust for the benefit of the Administrative Agent, the Issuing Banks, and the Lenders, and (y) the Defaulting Lender shall provide promptly to the Administrative Agent a statement describing in reasonable detail the Obligations owing to such Defaulting Lender as to which it exercised such right of setoff. The rights of each Lender, each Issuing Bank and their respective Affiliates under this Section are in addition to other rights and remedies (including other rights of setoff) that such Lender, such Issuing Bank or their respective Affiliates may have. Each Lender and Issuing Bank agrees to notify the Borrower and the Administrative Agent promptly after any such setoff and application; provided that the failure to give such notice shall not affect the validity of such setoff and application.

SECTION 9.09 Governing Law; Jurisdiction; Consent to Service of Process. (a) This Agreement and the other Loan Documents shall be construed in accordance with and governed by the law of the State of New York.

(b) Each of the Lenders and the Administrative Agent hereby irrevocably and unconditionally agrees that, notwithstanding the governing law provisions of any applicable Loan Document, any claims brought against the Administrative Agent by any Lender relating to this

Agreement, any other Loan Document or the consummation or administration of the transactions contemplated hereby or thereby shall be construed in accordance with and governed by the law of the State of New York.

(c) Each of the parties hereto hereby irrevocably and unconditionally submits, for itself and its property, to the exclusive jurisdiction of the United States District Court for the Southern District of New York sitting in the Borough of Manhattan (or if such court lacks subject matter jurisdiction, the Supreme Court of the State of New York sitting in the Borough of Manhattan), and any appellate court from any thereof, in any action or proceeding arising out of or relating to this Agreement or any other Loan Document or the transactions relating hereto or thereto, or for recognition or enforcement of any judgment, and each of the parties hereto hereby irrevocably and unconditionally agrees that all claims in respect of any such action or proceeding may (and any such claims brought against the Administrative Agent or any of its Related Parties may only) be heard and determined in such Federal (to the extent permitted by law) or New York State court. Each of the parties hereto agrees that a final judgment in any such action or proceeding shall be conclusive and may be enforced in other jurisdictions by suit on the judgment or in any other manner provided by law. Nothing in this Agreement or in any other Loan Document shall affect any right that the Administrative Agent, any Issuing Bank or any Lender may otherwise have to bring any action or proceeding relating to this Agreement against the Borrower, the Borrower or its properties in the courts of any jurisdiction.

(d) Each of the parties hereto hereby irrevocably and unconditionally waives, to the fullest extent it may legally and effectively do so, any objection which it may now or hereafter have to the laying of venue of any suit, action or proceeding arising out of or relating to this Agreement or any other Loan Document in any court referred to in paragraph (c) of this Section. Each of the parties hereto hereby irrevocably waives, to the fullest extent permitted by law, the defense of an inconvenient forum to the maintenance of such action or proceeding in any such court.

(e) Each party to this Agreement irrevocably consents to service of process in the manner provided for notices in Section 9.01. Nothing in this Agreement or any other Loan Document will affect the right of any party to this Agreement to serve process in any other manner permitted by law.

SECTION 9.10 WAIVER OF JURY TRIAL. EACH PARTY HERETO HEREBY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN ANY LEGAL PROCEEDING DIRECTLY OR INDIRECTLY ARISING OUT OF OR RELATING TO THIS AGREEMENT, ANY OTHER LOAN DOCUMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY OR THEREBY (WHETHER BASED ON CONTRACT, TORT OR ANY OTHER THEORY). EACH PARTY HERETO (A) CERTIFIES THAT NO REPRESENTATIVE, AGENT OR ATTORNEY OF ANY OTHER PARTY HAS REPRESENTED, EXPRESSLY OR OTHERWISE, THAT SUCH OTHER PARTY WOULD NOT, IN THE EVENT OF LITIGATION, SEEK TO ENFORCE THE FOREGOING WAIVER AND (B) ACKNOWLEDGES THAT IT AND THE OTHER PARTIES HERETO HAVE BEEN INDUCED TO ENTER INTO THIS AGREEMENT BY, AMONG OTHER THINGS, THE MUTUAL WAIVERS AND CERTIFICATIONS IN THIS SECTION.

SECTION 9.11 Headings. Article and Section headings and the Table of Contents used herein are for convenience of reference only, are not part of this Agreement and shall not affect the construction of, or be taken into consideration in interpreting, this Agreement.

SECTION 9.12 Confidentiality. Each of the Administrative Agent, the Issuing Banks and the Lenders agrees to maintain the confidentiality of the Information (as defined below), except that Information may be disclosed (a) to its and its Affiliates' directors, officers, employees and agents, including accountants, legal counsel and other advisors (it being understood that the Persons to whom such disclosure is made will be informed of the confidential nature of such Information and instructed to keep such Information confidential), (b) to the extent requested by any Governmental Authority (including any self-regulatory authority, such as the National Association of Insurance Commissioners), (c) to the extent required by applicable laws or regulations or by any subpoena or similar legal process, (d) to any other party to this Agreement, (e) in connection with the exercise of any remedies under this Agreement or any other Loan Document or any suit, action or proceeding relating to this Agreement or any other Loan Document or the enforcement of rights hereunder or thereunder, (f) subject to an agreement containing provisions substantially the same as those of this Section, to (1) any assignee of or Participant in, or any prospective assignee of or Participant in, any of its rights or obligations under this Agreement or (2) any actual or prospective counterparty (or its advisors) to any swap or derivative transaction relating to the Borrower and its obligations, (g) on a confidential basis to (1) any rating agency in connection with rating the Borrower or its Subsidiaries or the credit facilities provided for herein or (2) the CUSIP Service Bureau or any similar agency in connection with the issuance and monitoring of identification numbers with respect to the credit facilities provided for herein, (h) with the consent of the Borrower or (i) to the extent such Information (1) becomes publicly available other than as a result of a breach of this Section or (2) becomes available to the Administrative Agent, any Issuing Bank or any Lender on a nonconfidential basis from a source other than the Borrower. For the purposes of this Section, "Information" means all information received from the Borrower relating to the Borrower or its business, other than any such information that is available to the Administrative Agent, any Issuing Bank or any Lender on a nonconfidential basis prior to disclosure by the Borrower and other than information pertaining to this Agreement routinely provided by arrangers to data service providers, including league table providers, that serve the lending industry; provided that, in the case of information received from the Borrower after the date hereof, such information is clearly identified at the time of delivery as confidential. Any Person required to maintain the confidentiality of Information as provided in this Section shall be considered to have complied with its obligation to do so if such Person has exercised the same degree of care to maintain the confidentiality of such Information as such Person would accord to its own confidential information.

SECTION 9.13 Material Non-Public Information. (a) **EACH LENDER ACKNOWLEDGES THAT INFORMATION AS DEFINED IN SECTION 9.12 FURNISHED TO IT PURSUANT TO THIS AGREEMENT MAY INCLUDE MATERIAL NON-PUBLIC INFORMATION CONCERNING THE BORROWER AND ITS RELATED PARTIES OR THEIR RESPECTIVE SECURITIES, AND CONFIRMS THAT IT HAS DEVELOPED COMPLIANCE PROCEDURES REGARDING THE USE OF MATERIAL NON-PUBLIC INFORMATION AND THAT IT WILL HANDLE SUCH MATERIAL NON-PUBLIC INFORMATION IN ACCORDANCE WITH THOSE PROCEDURES AND APPLICABLE LAW, INCLUDING FEDERAL AND STATE SECURITIES LAWS**.

(b) **ALL INFORMATION, INCLUDING REQUESTS FOR WAIVERS AND AMENDMENTS, FURNISHED BY THE BORROWER OR THE ADMINISTRATIVE AGENT PURSUANT TO, OR IN THE COURSE OF ADMINISTERING, THIS AGREEMENT WILL BE SYNDICATE-LEVEL INFORMATION, WHICH MAY CONTAIN MATERIAL NON-PUBLIC INFORMATION ABOUT THE BORROWER AND ITS RELATED PARTIES OR ITS RESPECTIVE SECURITIES. ACCORDINGLY, EACH LENDER REPRESENTS TO THE BORROWER AND THE ADMINISTRATIVE AGENT THAT IT HAS IDENTIFIED IN ITS ADMINISTRATIVE QUESTIONNAIRE A CREDIT CONTACT WHO MAY RECEIVE INFORMATION THAT MAY CONTAIN MATERIAL NON-PUBLIC INFORMATION IN ACCORDANCE WITH ITS COMPLIANCE PROCEDURES AND APPLICABLE LAW.**

SECTION 9.14 USA PATRIOT Act. Each Lender that is subject to the requirements of the USA PATRIOT Act of 2001 (the "Patriot Act") hereby notifies the Borrower that pursuant to the requirements of the Patriot Act, it is required to obtain, verify and record information that identifies the Borrower, which information includes the name and address of the Borrower and other information that will allow such Lender to identify the Borrower in accordance with the Patriot Act.

SECTION 9.15 Intentionally Omitted.

SECTION 9.16 Interest Rate Limitation. Notwithstanding anything herein to the contrary, if at any time the interest rate applicable to any Loan, together with all fees, charges and other amounts which are treated as interest on such Loan under applicable law (collectively the "Charges"), shall exceed the maximum lawful rate (the "Maximum Rate") which may be contracted for, charged, taken, received or reserved by the Lender holding such Loan in accordance with applicable law, the rate of interest payable in respect of such Loan hereunder, together with all Charges payable in respect thereof, shall be limited to the Maximum Rate and, to the extent lawful, the interest and Charges that would have been payable in respect of such Loan but were not payable as a result of the operation of this Section shall be cumulated and the interest and Charges payable to such Lender in respect of other Loans or periods shall be increased (but not above the Maximum Rate therefor) until such cumulated amount, together with interest thereon at the NYFRB Rate to the date of repayment, shall have been received by such Lender.

SECTION 9.17 No Fiduciary Duty, etc. The Borrower acknowledges and agrees, and acknowledges its Subsidiaries' understanding, that no Credit Party will have any obligations except those obligations expressly set forth herein and in the other Loan Documents and each Credit Party is acting solely in the capacity of an arm's length contractual counterparty to the Borrower with respect to the Loan Documents and the transactions contemplated therein and not as a financial advisor or a fiduciary to, or an agent of, the Borrower or any other person. The Borrower agrees that it will not assert any claim against any Credit Party based on an alleged breach of fiduciary duty by such Credit Party in connection with this Agreement and the transactions contemplated hereby. Additionally, the Borrower acknowledges and agrees that no Credit Party is advising the Borrower as to any legal, tax, investment, accounting, regulatory or any other matters in any jurisdiction. The Borrower shall consult with its own advisors concerning such matters and shall be responsible for making its own independent investigation and appraisal of the transactions contemplated hereby, and the Credit Parties shall have no responsibility or liability to the Borrower with respect thereto.

The Borrower further acknowledges and agrees, and acknowledges its Subsidiaries' understanding, that each Credit Party, together with its Affiliates, is a full service securities or banking firm engaged in securities trading and brokerage activities as well as providing investment banking and other financial services. In the ordinary course of business, any Credit Party may provide investment banking and other financial services to, and/or acquire, hold or sell, for its own accounts and the accounts of customers, equity, debt and other securities and financial instruments (including bank loans and other obligations) of, the Borrower and other companies with which it may have commercial or other relationships. With respect to any securities and/or financial instruments so held by any Credit Party or any of its customers, all rights in respect of such securities and financial instruments, including any voting rights, will be exercised by the holder of the rights, in its sole discretion.

In addition, the Borrower acknowledges and agrees, and acknowledges its Subsidiaries' understanding, that each Credit Party and its affiliates may be providing debt financing, equity capital or other services (including financial advisory services) to other companies in respect of which the Borrower or its Subsidiaries may have conflicting interests regarding the transactions described herein and otherwise. No Credit Party will use confidential information obtained from the Borrower by virtue of the transactions contemplated by the Loan Documents or its other relationships with the Borrower in connection with the performance by such Credit Party of services for other companies, and no Credit Party will furnish any such information to other companies. The Borrower also acknowledges that no Credit Party has any obligation to use in connection with the transactions contemplated by the Loan Documents, or to furnish to the Borrower, confidential information obtained from other companies.

SECTION 9.18 Acknowledgment and Consent to Bail-In of Affected Financial Institutions. Notwithstanding anything to the contrary in any Loan Document or in any other agreement, arrangement or understanding among any such parties, each party hereto acknowledges that any liability of any Affected Financial Institution arising under any Loan Document may be subject to the Write-Down and Conversion Powers of the applicable Resolution Authority and agrees and consents to, and acknowledges and agrees to be bound by:

(a) the application of any Write-Down and Conversion Powers by the applicable Resolution Authority to any such liabilities arising hereunder which may be payable to it by any party hereto that is an Affected Financial Institution; and

(b) the effects of any Bail-In Action on any such liability, including, if applicable:

(i) a reduction in full or in part or cancellation of any such liability;

(ii) a conversion of all, or a portion of, such liability into shares or other instruments of ownership in such Affected Financial Institution, its parent entity, or a bridge institution that may be issued to it or otherwise conferred on it, and that such shares or other instruments of ownership will be accepted by it in lieu of any rights with respect to any such liability under this Agreement or any other Loan Document; or

(iii) the variation of the terms of such liability in connection with the exercise of the Write-Down and Conversion Powers of the applicable Resolution Authority.

[Signature Pages on file with the Administrative Agent]

EXHIBIT F-1

FORM OF BORROWING REQUEST

JPMorgan Chase Bank, N.A.,
as Administrative Agent
for the Lenders referred to below
131 South Dearborn, Floor 04
Chicago, Illinois 60603-5506
Attention: Kathryn V Tyler
Facsimile: (844) 490-5663
Email Address: katy.tyler@chase.com

Re: Northwest Natural Holding Company

[Date]

Ladies and Gentlemen:

Reference is hereby made to the Amended and Restated Credit Agreement dated as of November 3, 2021 (as the same may be amended, restated, supplemented or otherwise modified from time to time, the "Credit Agreement"), among Northwest Natural Holding Company (the "Borrower"), the Lenders from time to time party thereto and JPMorgan Chase Bank, N.A., as administrative agent (in such capacity, the "Administrative Agent"). Capitalized terms used but not defined herein shall have the meanings assigned to such terms in the Credit Agreement. The Borrower hereby gives you notice pursuant to Section 2.03 of the Credit Agreement that it requests a Borrowing under the Credit Agreement, and in that connection the Borrower specifies the following information with respect to such Borrowing requested hereby:

1. Aggregate principal amount of Borrowing:[1] __________

2. Date of Borrowing[2] (which shall be a Business Day): __________

3. Type of Borrowing[3]: __________

4. Interest Period and the last day thereof (if a Term Benchmark Borrowing):[4] __________

5. Location and number of the Borrower's account or any other account agreed upon by the Administrative Agent and the Borrower to which proceeds of Borrowing are to be disbursed: __________

[Signature Page Follows]

---

[1] Not less than applicable amounts specified in Section 2.02(c).

[2] For RFR Loans based on Daily Simple SOFR, the date should be 5 Business Days after the date of the Borrowing Request.

[3] Specify ABR Borrowing or Term Benchmark Borrowing or RFR Borrowing. If no election as to the Type of Borrowing specified, then the requested Borrowing shall be an ABR Borrowing.

[4] Which must comply with the definition of "Interest Period" and end not later than the Maturity Date.

The undersigned hereby represents and warrants that the conditions to lending specified in Section 4.02 of the Credit Agreement are satisfied as of the date hereof.

Very truly yours,

NORTHWEST NATURAL HOLDING COMPANY,

as the Borrower

By: ______________________________
Name:
Title:

EXHIBIT F-2

FORM OF INTEREST ELECTION REQUEST

JPMorgan Chase Bank, N.A.,
as Administrative Agent
for the Lenders referred to below
131 South Dearborn, Floor 04
Chicago, Illinois 60603-5663
Attention: Kathryn V Tyler
Facsimile: (844) 490-5663
Email Address: katy.tyler@chase.com

Re: Northwest Natural Holding Company

[Date]

Ladies and Gentlemen:

Reference is hereby made to the Amended and Restated Credit Agreement dated as of November 3, 2021 (as the same may be amended, restated, supplemented or otherwise modified from time to time, the "Credit Agreement"), among Northwest Natural Holding Company (the "Borrower"), the Lenders from time to time party thereto and JPMorgan Chase Bank, N.A., as administrative agent (in such capacity, the "Administrative Agent"). Capitalized terms used but not defined herein shall have the meanings assigned to such terms in the Credit Agreement. The Borrower hereby gives you notice pursuant to Section 2.08 of the Credit Agreement that it requests to [convert][continue] an existing Borrowing under the Credit Agreement, and in that connection the Borrower specifies the following information with respect to such [conversion][continuation] requested hereby:

1. List date, Type, principal amount and Interest Period (if applicable) of existing Borrowing: __________

2. Aggregate principal amount of resulting Borrowing: __________

3. Effective date of interest election (which shall be a Business Day): __________

4. Type of Borrowing: __________

5. Interest Period and the last day thereof (if a Term Benchmark Borrowing):[5] __________

[Signature Page Follows]

[5] Applicable to Term Benchmark Borrowings only. Shall be subject to the definition of "Interest Period" and can be a period of one, three or six months. Cannot extend beyond the Maturity Date. If an Interest Period is not specified, then the Borrower shall be deemed to have selected an Interest Period of one month's duration.

Very truly yours,

NORTHWEST NATURAL HOLDING COMPANY,

as the Borrower

By: ______________________________
Name:
Title:

EXHIBIT A CONFORMED THROUGH AMENDMENT NO. 1
DATED JANUARY 20, 2023

EXECUTION VERSION

J.P.Morgan

AMENDED AND RESTATED CREDIT AGREEMENT

dated as of

November 3, 2021

among

NORTHWEST NATURAL GAS COMPANY,

The Lenders Party Hereto

JPMORGAN CHASE BANK, N.A.
as Administrative Agent

BANK OF AMERICA, N.A.,
U.S. BANK NATIONAL ASSOCIATION
and
WELLS FARGO BANK, NATIONAL ASSOCIATION,
as Co-Syndication Agents

J.P. MORGAN SECURITIES LLC,
as Sustainability Structuring Agent
JPMORGAN CHASE BANK, N.A.,
BOFA SECURITIES, INC.,
U.S. BANK NATIONAL ASSOCIATION and WELLS FARGO SECURITIES, LLC,
as Joint Bookrunners and Co-Lead Arrangers

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AMENDED AND RESTATED CREDIT AGREEMENT (this "Agreement") dated as of November 3, 2021 among NORTHWEST NATURAL GAS COMPANY, the LENDERS from time to time party hereto, JPMORGAN CHASE BANK, N.A., as Administrative Agent, and BANK OF AMERICA, N.A., U.S. BANK NATIONAL ASSOCIATION and WELLS FARGO BANK, NATIONAL ASSOCIATION, as Co-Syndication Agents.

WHEREAS, the Borrower, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent thereunder, are currently party to that certain Credit Agreement, dated as of October 2, 2018 (as amended, supplemented or otherwise modified prior to the Restatement Effective Date, the "Existing Credit Agreement");

WHEREAS, the Borrower, the Lenders party hereto and the Administrative Agent have agreed to enter into this Agreement in order to (i) amend and restate the Existing Credit Agreement in its entirety, (ii) extend the maturity date in respect of the existing revolving credit facility under the Existing Credit Agreement, (iii) re-evidence the "Obligations" under, and as defined in, the Existing Credit Agreement, which shall be repayable in accordance with the terms of this Agreement, and (iv) set forth the terms and conditions under which the Lenders will, from time to time, make loans and extend other financial accommodations to or for the benefit of the Borrower;

WHEREAS, it is the intent of the parties hereto that this Agreement not constitute a novation of the obligations and liabilities of the parties under the Existing Credit Agreement or be deemed to evidence or constitute full repayment of such obligations and liabilities, but that this Agreement amend and restate in its entirety the Existing Credit Agreement and re-evidence the obligations and liabilities of the Borrower outstanding thereunder, which shall be payable in accordance with the terms hereof; and

WHEREAS, it is also the intent of the Borrower to confirm that all obligations under the applicable "Loan Documents" (as referred to and defined in the Existing Credit Agreement) shall continue in full force and effect as modified or restated by the Loan Documents (as referred to and defined herein) and that, from and after the Restatement Effective Date, all references to the "Credit Agreement" contained in any such existing "Loan Documents" shall be deemed to refer to this Agreement;

NOW, THEREFORE, in consideration of the premises and the mutual covenants contained herein, the parties hereto agree that the Existing Credit Agreement is hereby amended and restated as follows:

ARTICLE I

Definitions

SECTION 1.01 Defined Terms. As used in this Agreement, the following terms have the meanings specified below:

"ABR", when used in reference to any Loan or Borrowing, refers to whether such Loan, or the Loans comprising such Borrowing, bears interest at a rate determined by reference to the Alternate Base Rate.

"Adjusted Daily Simple SOFR" means an interest rate per annum equal to (a) the Daily Simple SOFR, *plus* (b) 0.10%; provided that if the Adjusted Daily Simple SOFR as so determined would be less than the Floor, such rate shall be deemed to be equal to the Floor for the purposes of this Agreement.

"Adjusted Term SOFR Rate" means, for any Interest Period, an interest rate per annum equal to (a) the Term SOFR Rate for such Interest Period, *plus* (b) 0.10%; provided that if the Adjusted Term SOFR Rate as so determined would be less than the Floor, such rate shall be deemed to be equal to the Floor for the purposes of this Agreement.

"Administrative Agent" means JPMorgan Chase Bank, N.A. (including its branches and affiliates), in its capacity as administrative agent for the Lenders hereunder, and any successor appointed in accordance with Article VIII.

"Administrative Questionnaire" means an Administrative Questionnaire in a form supplied by the Administrative Agent.

"Affected Financial Institution" means (a) any EEA Financial Institution or (b) any UK Financial Institution.

"Affiliate" means, with respect to a specified Person, another Person that directly, or indirectly through one or more intermediaries, Controls or is Controlled by or is under common Control with the Person specified.

"Agent-Related Person" has the meaning assigned to such term in Section 9.03(c).

"Aggregate Commitment" means the aggregate of the Commitments of all of the Lenders, as reduced or increased from time to time pursuant to the terms and conditions hereof. As of the Restatement Effective Date, the Aggregate Commitment is $400,000,000.

"Alternate Base Rate" means, for any day, a rate *per annum* equal to the greatest of (a) the Prime Rate in effect on such day, (b) the NYFRB Rate in effect on such day plus 1/2 of 1% and (c) the Adjusted Term SOFR Rate for a one month Interest Period as published two U.S. Government Securities Business Days prior to such day (or if such day is not a U.S. Government Securities Business Day, the immediately preceding U.S. Government Securities Business Day) plus 1%; provided that for the purpose of this definition, the Adjusted Term SOFR Rate for any day shall be based on the Term SOFR Reference Rate at approximately 5:00 a.m. Chicago time on such day (or any amended publication time for the Term SOFR Reference Rate), as specified by the CME Term SOFR Administrator in the Term SOFR Reference Rate methodology. Any change in the Alternate Base Rate due to a change in the Prime Rate, the NYFRB Rate or the Adjusted Term SOFR Rate shall be effective from and including the effective date of such change in the Prime Rate, the NYFRB Rate or the Adjusted Term SOFR Rate, respectively. If the Alternate Base Rate is being used as an alternate rate of interest pursuant to Section 2.14 (for the avoidance of doubt, only until the Benchmark Replacement has been determined pursuant to Section 2.14(b)), then the Alternate Base Rate shall be the greater of clauses (a) and (b) above and shall be determined without reference to clause (c) above. For the avoidance of doubt, if the Alternate Base Rate as determined pursuant to the foregoing would be less than 1.0%, such rate shall be deemed to be 1.0% for purposes of this Agreement.

"Amendment No. 1" means that certain Amendment No. 1 to Amended and Restated Credit Agreement, dated as of January 20, 2023, among the Borrower, the Administrative Agent and the Lenders party thereto.

"Amendment No. 1 Effective Date" means the date on which each of the conditions set forth in Section 2 of Amendment No. 1 are satisfied (or waived), which date is January 20, 2023.

"Ancillary Document" has the meaning assigned to it in Section 9.06(b).

"Anti-Corruption Laws" means all laws, rules, and regulations of any jurisdiction applicable to the Borrower or any of its Subsidiaries from time to time concerning or relating to money laundering, bribery or corruption.

"Applicable Party" has the meaning assigned to it in Section 8.03(c).

"Applicable Percentage" means, with respect to any Lender, the percentage of the Aggregate Commitment represented by such Lender's Commitment; provided that, in the case of Section 2.21 when a Defaulting Lender shall exist, "Applicable Percentage" shall mean the percentage of the Aggregate Commitment (disregarding any Defaulting Lender's Commitment) represented by such

Lender's Commitment. If the Commitments have terminated or expired, the Applicable Percentages shall be determined based upon the Commitments most recently in effect, giving effect to any assignments and to any Lender's status as a Defaulting Lender at the time of determination.

"Applicable Rate" means, for any day, with respect to any Term Benchmark Loan or any ABR Loan or with respect to the facility fees payable hereunder, as the case may be, the applicable rate per annum set forth below under the caption "Term Benchmark and RFR Spread", "ABR Spread" or "Facility Fee Rate", as the case may be, based upon the Debt Rating applicable on such date:

Pricing Level	Debt Rating:	Term Benchmark and RFR Spread	ABR Spread	Facility Fee Rate
Level I	AA- or higher / Aa3 or higher	0.680%	0.000%	0.070%
Level II	A+ / A1	0.795%	0.000%	0.080%
Level III	A / A2	0.900%	0.000%	0.100%
Level IV	A- / A3	1.000%	0.000%	0.125%
Level V	BBB+ / Baa1	1.075%	0.075%	0.175%
Level VI	BBB or below / Baa2 or below	1.275%	0.275%	0.225%

For purposes of the foregoing, (i) if only one of S&P and Moody's shall have in effect a Debt Rating, the applicable Pricing Level shall be determined by reference to the available rating; (ii) if neither S&P nor Moody's shall have in effect a Debt Rating, the applicable Pricing Level will be set in accordance with Level VI; (iii) if the ratings established or deemed to have been established by Moody's and S&P for the Debt Rating shall fall within different Pricing Levels, the applicable Pricing Level shall be based on the better of the two ratings unless the ratings are not in two adjacent Pricing Levels, in which case the applicable Pricing Level shall be determined by reference to the Pricing Level one level below the Pricing Level corresponding to the better of the two ratings; and (iv) if the Debt Ratings established or deemed to have been established by Moody's and S&P shall be changed, such change shall be effective as of the date on which it is first publicly announced by the applicable rating agency. Each change in Pricing Level shall apply during the period commencing on the effective date of such change and ending on the date immediately preceding the effective date of the next such change.

It is hereby understood and agreed that the "Term Benchmark and RFR Spread" (including with respect to the Letter of Credit fees payable pursuant to Section 2.12(b)(i)) and the "ABR Spread" set forth in the table above shall be adjusted from time to time based upon the Sustainability Rate Adjustment and "Facility Fee Rate" set forth in the table above shall be adjusted from time to time based upon the Sustainability Facility Fee Adjustment, in each case to be calculated and applied as set forth in Section 1.08; provided, that in no event shall the Applicable Rate be less than zero.

"Approved Electronic Platform" has the meaning assigned to it in Section 8.03(a).

"Approved Fund" has the meaning assigned to such term in Section 9.04(b).

"Arrangers" means each of JPMorgan Chase Bank, N.A., BofA Securities, Inc., U.S. Bank National Association and Wells Fargo Securities, LLC, in their respective capacities as joint bookrunners and co-lead arrangers hereunder.

"Assignment and Assumption" means an assignment and assumption entered into by a Lender and an assignee (with the consent of any party whose consent is required by Section 9.04), and accepted by the Administrative Agent, in the form of Exhibit A or any other form (including electronic records generated by the use of an electronic platform) approved by the Administrative Agent.

"Augmenting Lender" has the meaning assigned to such term in Section 2.20.

"Authorized Officer" means the chief executive officer, the president, any vice president, the treasurer or any assistant treasurer of the Borrower.

"Availability Period" means the period from and including the Restatement Effective Date to but excluding the earlier of the Maturity Date and the date of termination of the Commitments.

"Available Tenor" means, as of any date of determination and with respect to the then-current Benchmark, as applicable, any tenor for such Benchmark (or component thereof) or payment period for interest calculated with reference to such Benchmark (or component thereof), as applicable, that is or may be used for determining the length of an Interest Period for any term rate or otherwise, for determining any frequency of making payments of interest calculated pursuant to this Agreement as of such date and not including, for the avoidance of doubt, any tenor for such Benchmark that is then-removed from the definition of "Interest Period" pursuant to clause (e) of Section 2.14.

"Bail-In Action" means the exercise of any Write-Down and Conversion Powers by the applicable Resolution Authority in respect of any liability of an Affected Financial Institution.

"Bail-In Legislation" means (a) with respect to any EEA Member Country implementing Article 55 of Directive 2014/59/EU of the European Parliament and of the Council of the European Union, the implementing law, regulation rule or requirement for such EEA Member Country from time to time which is described in the EU Bail-In Legislation Schedule and (b) with respect to the United Kingdom, Part I of the United Kingdom Banking Act 2009 (as amended from time to time) and any other law, regulation or rule applicable in the United Kingdom relating to the resolution of unsound or failing banks, investment firms or other financial institutions or their affiliates (other than through liquidation, administration or other insolvency proceedings).

"Bankruptcy Event" means, with respect to any Person, such Person becomes the subject of a voluntary or involuntary bankruptcy or insolvency proceeding, or has had a receiver, conservator, trustee, administrator, custodian, assignee for the benefit of creditors or similar Person charged with the reorganization or liquidation of its business appointed for it, or, in the good faith determination of the Administrative Agent, has taken any action in furtherance of, or indicating its consent to, approval of, or acquiescence in, any such proceeding or appointment or has had any order for relief in such proceeding entered in respect thereof, provided that a Bankruptcy Event shall not result solely by virtue of any ownership interest, or the acquisition of any ownership interest, in such Person by a Governmental Authority or instrumentality thereof, unless such ownership interest results in or provides such Person with immunity from the jurisdiction of courts within the United States or from the enforcement of judgments or writs of attachment on its assets or permits such Person (or such Governmental Authority or instrumentality) to reject, repudiate, disavow or disaffirm any contracts or agreements made by such Person.

"Benchmark" means, initially, with respect to any (i) RFR Loan (following a Benchmark Transition Event and Benchmark Replacement Date with respect to the Term SOFR Rate), Daily Simple SOFR or (ii) Term Benchmark Loan, the Term SOFR Rate; provided that if a Benchmark Transition Event and the related Benchmark Replacement Date have occurred with respect to the Daily Simple SOFR or Term SOFR Rate, as applicable, or the then-current Benchmark, then "Benchmark" means the applicable Benchmark Replacement to the extent that such Benchmark Replacement has replaced such prior benchmark rate pursuant to clause (b) of Section 2.14.

"Benchmark Replacement" means, for any Available Tenor, the first alternative set forth in the order below that can be determined by the Administrative Agent for the applicable Benchmark Replacement Date:

(1) the sum of: (a) Daily Simple SOFR and (b) the related Benchmark Replacement Adjustment,

(2) the sum of: (a) the alternate benchmark rate that has been selected by the Administrative Agent and the Borrower as the replacement for the then-current Benchmark for the applicable Corresponding Tenor giving due consideration to (i) any selection or recommendation of a replacement benchmark rate or the mechanism for determining such a rate by the Relevant Governmental Body or (ii) any evolving or then-prevailing market convention for determining a benchmark rate as a replacement for the then-current Benchmark for Dollar-denominated syndicated credit facilities at such time in the United States and (b) the related Benchmark Replacement Adjustment.

If the Benchmark Replacement as determined pursuant to the above would be less than the Floor, the Benchmark Replacement will be deemed to be the Floor for the purposes of this Agreement and the other Loan Documents.

"Benchmark Replacement Adjustment" means, with respect to any replacement of the then-current Benchmark with an Unadjusted Benchmark Replacement for any applicable Interest Period and Available Tenor for any setting of such Unadjusted Benchmark Replacement, the spread adjustment, or method for calculating or determining such spread adjustment, (which may be a positive or negative value or zero) that has been selected by the Administrative Agent and the Borrower for the applicable Corresponding Tenor giving due consideration to (i) any selection or recommendation of a spread adjustment, or method for calculating or determining such spread adjustment, for the replacement of such Benchmark with the applicable Unadjusted Benchmark Replacement by the Relevant Governmental Body on the applicable Benchmark Replacement Date and/or (ii) any evolving or then-prevailing market convention for determining a spread adjustment, or method for calculating or determining such spread adjustment, for the replacement of such Benchmark with the applicable Unadjusted Benchmark Replacement for syndicated credit facilities denominated in Dollars at such time.

"Benchmark Replacement Conforming Changes" means, with respect to any Benchmark Replacement and/or any Term Benchmark Loan, any technical, administrative or operational changes (including changes to the definition of "Alternate Base Rate," the definition of "Business Day," the definition of "U.S. Government Securities Business Day," the definition of "Interest Period," timing and frequency of determining rates and making payments of interest, timing of borrowing requests or prepayment, conversion or continuation notices, length of lookback periods, the applicability of breakage provisions, and other technical, administrative or operational matters) that the Administrative Agent decides may be appropriate to reflect the adoption and implementation of any applicable Benchmark and to permit the administration thereof by the Administrative Agent in a manner substantially consistent with market practice (or, if the Administrative Agent decides that adoption of any portion of such market practice is not administratively feasible or if the Administrative Agent determines that no market practice for the administration of such Benchmark exists, in such other manner of administration as the Administrative Agent decides is reasonably necessary in connection with the administration of this Agreement and the other Loan Documents).

"Benchmark Replacement Date" means, with respect to any Benchmark, the earliest to occur of the following events with respect to such then-current Benchmark:

(1) in the case of clause (1) or (2) of the definition of "Benchmark Transition Event," the later of (a) the date of the public statement or publication of information referenced therein and (b) the date on which the administrator of such Benchmark (or the published component used in the calculation thereof) permanently or indefinitely ceases to provide all Available Tenors of such Benchmark (or such component thereof); or

(2) in the case of clause (3) of the definition of "Benchmark Transition Event," the first date on which such Benchmark (or the published component used in the calculation thereof) has been determined and announced by the regulatory supervisor for the administrator of such Benchmark (or such component thereof) to be no longer representative; provided that such non-representativeness will be determined by reference to the most recent statement or publication

referenced in such clause (3) and even if any Available Tenor of such Benchmark (or such component thereof) continues to be provided on such date.

For the avoidance of doubt, (i) if the event giving rise to the Benchmark Replacement Date occurs on the same day as, but earlier than, the Reference Time in respect of any determination, the Benchmark Replacement Date will be deemed to have occurred prior to the Reference Time for such determination and (ii) the "Benchmark Replacement Date" will be deemed to have occurred in the case of clause (1) or (2) with respect to any Benchmark upon the occurrence of the applicable event or events set forth therein with respect to all then-current Available Tenors of such Benchmark (or the published component used in the calculation thereof).

"Benchmark Transition Event" means, with respect to any Benchmark, the occurrence of one or more of the following events with respect to such then-current Benchmark:

(1) a public statement or publication of information by or on behalf of the administrator of such Benchmark (or the published component used in the calculation thereof) announcing that such administrator has ceased or will cease to provide all Available Tenors of such Benchmark (or such component thereof), permanently or indefinitely, provided that, at the time of such statement or publication, there is no successor administrator that will continue to provide any Available Tenor of such Benchmark (or such component thereof);

(2) a public statement or publication of information by the regulatory supervisor for the administrator of such Benchmark (or the published component used in the calculation thereof), the Federal Reserve Board, the NYFRB, the CME Term SOFR Administrator, an insolvency official with jurisdiction over the administrator for such Benchmark (or such component), a resolution authority with jurisdiction over the administrator for such Benchmark (or such component), in each case, or a court or an entity with similar insolvency or resolution authority over the administrator for such Benchmark (or such component), in each case, which states that the administrator of such Benchmark (or such component) has ceased or will cease to provide all Available Tenors of such Benchmark (or such component thereof) permanently or indefinitely; provided that, at the time of such statement or publication, there is no successor administrator that will continue to provide any Available Tenor of such Benchmark (or such component thereof); or

(3) a public statement or publication of information by the regulatory supervisor for the administrator of such Benchmark (or the published component used in the calculation thereof) announcing that all Available Tenors of such Benchmark (or such component thereof) are no longer, or as of a specified future date will no longer be, representative.

For the avoidance of doubt, a "Benchmark Transition Event" will be deemed to have occurred with respect to any Benchmark if a public statement or publication of information set forth above has occurred with respect to each then-current Available Tenor of such Benchmark (or the published component used in the calculation thereof).

"Benchmark Unavailability Period" means, with respect to any Benchmark, the period (if any) (x) beginning at the time that a Benchmark Replacement Date pursuant to clauses (1) or (2) of that definition has occurred if, at such time, no Benchmark Replacement has replaced such then-current Benchmark for all purposes hereunder and under any Loan Document in accordance with Section 2.14 and (y) ending at the time that a Benchmark Replacement has replaced such then-current Benchmark for all purposes hereunder and under any Loan Document in accordance with Section 2.14.

"Beneficial Ownership Certification" means a certification regarding beneficial ownership or control as required by the Beneficial Ownership Regulation.

"Beneficial Ownership Regulation" means 31 C.F.R. § 1010.230.

"Benefit Plan" means any of (a) an "employee benefit plan" (as defined in Section 3(3) of ERISA) that is subject to Title I of ERISA, (b) a "plan" as defined in Section 4975 of the Code to which

Section 4975 of the Code applies, and (c) any Person whose assets include (for purposes of the Plan Asset Regulations or otherwise for purposes of Title I of ERISA or Section 4975 of the Code) the assets of any such "employee benefit plan" or "plan".

"Borrower" means Northwest Natural Gas Company, an Oregon corporation.

"Borrower Materials" has the meaning assigned to such term in Section 5.02.

"Borrowing" means (a) Revolving Loans of the same Type, made, converted or continued on the same date and, in the case of Term Benchmark Loans, as to which a single Interest Period is in effect or (b) a Swingline Loan.

"Borrowing Request" means a request by the Borrower for a Revolving Borrowing in accordance with Section 2.03, which shall be substantially in the form attached hereto as Exhibit F-1 or any other form approved by the Administrative Agent.

"Business Day" means, any day (other than a Saturday or a Sunday) on which banks are open for business in New York City; provided that, in addition to the foregoing, a Business Day shall be a day that is also a U.S. Government Securities Business Day (a) in relation to RFR Loans and any interest rate settings, fundings, disbursements, settlements or payments of any such RFR Loan, or any other dealings of such RFR Loan and (b) in relation to Loans referencing the Adjusted Term SOFR Rate and any interest rate settings, fundings, disbursements, settlements or payments of any such Loans referencing the Adjusted Term SOFR Rate or any other dealings of such Loans referencing the Adjusted Term SOFR Rate.

"Carbon Savings KPI" means aggregate metric tons of greenhouse gasses saved since 2015 by the Borrower, as determined and calculated by the Borrower using the Carbon Savings KPI Calculation Methodology.

"Carbon Savings KPI Calculation Methodology" means the calculation methodology used by the Borrower to report carbon savings of 379,064 metric tons in Holdings' 2020 Environmental, Social and Governance Report (a copy of which report has been delivered to the Administrative Agent, the Sustainability Structuring Agent and the Lenders prior to the Restatement Effective Date or otherwise published on an Internet or intranet website to which each Lender, the Sustainability Structuring Agent and the Administrative Agent have been granted access free of charge (or at the expense of the Borrower)), and as identified in the Baseline column of the Sustainability Table.

"Carbon Savings KPI Applicable Rate Adjustment Amount" means, with respect to any period between Sustainability Pricing Adjustment Dates, (a) positive 0.020%, if the Carbon Savings KPI for such period as set forth in the KPI Metrics Report is less than the Carbon Savings KPI Threshold A for such period, (b) 0.000%, if the Carbon Savings KPI for such period as set forth in the KPI Metrics Report is more than or equal to the Carbon Savings KPI Threshold A for such period but less than the Carbon Savings KPI Target A for such period, and (c) negative 0.020%, if the Carbon Savings KPI for such period as set forth in the KPI Metrics Report is more than or equal to Carbon Savings KPI Target A for such period.

"Carbon Savings KPI Facility Fee Adjustment Amount" means, with respect to any period between Sustainability Pricing Adjustment Dates, (a) positive 0.005%, if the Carbon Savings KPI for such period as set forth in the KPI Metrics Report is less than the Carbon Savings KPI Threshold A for such period, (b) 0.000%, if the Carbon Savings KPI for such period as set forth in the KPI Metrics Report is more than or equal to the Carbon Savings KPI Threshold A for such period but less than the Carbon Savings KPI Target A for such period, and (c) negative 0.005%, if the Carbon Savings KPI for such period as set forth in the KPI Metrics Report is more than or equal to Carbon Savings KPI Target A for such period.

"Carbon Savings KPI Target A" means, with respect to any Reference Year, the Carbon Savings KPI Target A for such Reference Year as set forth in the Sustainability Table.

"Carbon Savings KPI Threshold A" means, with respect to any Reference Year, the Carbon Savings KPI Threshold A for such Reference Year as set forth in the Sustainability Table.

"Change in Control" means that (a)(i) either (x) a person or group (as defined in the Securities Exchange Act of 1934) has acquired more than 50% of the voting stock of Holdings or (y) a majority of the board of directors of Holdings shall cease to be composed of individuals who were members of such board on the Restatement Effective Date ("Existing Directors") or were approved by a majority of the Existing Directors and previously approved directors; and (ii) at the time of, or at any time during the one-year period following, an event described in the preceding clause (a)(i), the Borrower either (x) has a rating that is not an Investment Grade Rating from any one of S&P, Fitch or Moody's or (y) does not have a credit rating from at least one of S&P, Fitch or Moody's or (b) Holdings shall cease to own, directly or indirectly, 100% of the Equity Interests of the Borrower (other than a single share of the junior preferred capital stock of the Borrower held by an independent third party), free and clear of any lien, pledge, charge or other security interest.

"Change in Law" means the occurrence, after the date of this Agreement (or, with respect to any Lender, such later date on which such Lender becomes a party to this Agreement), of: (a) the adoption or taking effect of any law, rule, regulation or treaty, (b) any change in any law, rule, regulation or treaty or in the administration, interpretation, implementation or application thereof by any Governmental Authority, or (c) compliance by any Lender or Issuing Bank (or, for purposes of Section 2.15(b), by any lending office of such Lender or by such Lender's or Issuing Bank's holding company, if any) with any request, rule, guideline, requirement or directive (whether or not having the force of law) of any Governmental Authority made or issued after the date of this Agreement; provided that, notwithstanding anything herein to the contrary, (x) the Dodd-Frank Wall Street Reform and Consumer Protection Act and all requests, rules, guidelines, requirements or directives thereunder, or issued in connection therewith or in the implementation thereof, and (y) all requests, rules, guidelines, requirements and directives promulgated by the Bank for International Settlements, the Basel Committee on Banking Supervision (or any successor or similar authority) or the United States or foreign regulatory authorities, in each case pursuant to Basel III, shall in each case be deemed to be a "Change in Law" regardless of the date enacted, adopted, issued or implemented.

"Charges" has the meaning assigned to it in Section 9.16.

"Class", when used in reference to any Loan or Borrowing, refers to whether such Loan, or the Loans comprising such Borrowing, are Revolving Loans or Swingline Loans.

"CME Term SOFR Administrator" means CME Group Benchmark Administration Limited as administrator of the forward-looking term Secured Overnight Financing Rate (SOFR) (or a successor administrator).

"Co-Syndication Agents" means each of Bank of America, N.A., U.S. Bank National Association and Wells Fargo Bank, National Association.

"Code" means the Internal Revenue Code of 1986, as amended.

"Commissions" means, collectively, the Oregon Public Utility Commission and the Washington Utilities and Transportation Commission.

"Commitment" means, with respect to each Lender, the commitment of such Lender to make Revolving Loans and to acquire participations in Letters of Credit and Swingline Loans hereunder, expressed as an amount representing the maximum aggregate amount of such Lender's Revolving Credit Exposure hereunder, as such commitment may be (a) reduced or terminated from time to time pursuant to Section 2.09, (b) increased from time to time pursuant to Section 2.20 and (c) reduced or increased from time to time pursuant to assignments by or to such Lender pursuant to Section 9.04. The initial amount of each Lender's Commitment is set forth on Schedule 2.01A, or in the Assignment and Assumption or other documentation or record (as such term is defined in Section 9-102(a)(70) of the New York Uniform Commercial Code) as provided in Section 9.04(b)(ii)(C), pursuant to which such Lender shall have assumed its Commitment, as applicable.

"Commitment Schedule" means Schedule 2.01A and Schedule 2.01B attached hereto, as the context may require.

"Communications" has the meaning assigned to such term in Section 8.03(c).

"Connection Income Taxes" means Other Connection Taxes that are imposed on or measured by net income (however denominated) or that are gross receipts or franchise Taxes or branch profits Taxes.

"Consolidated Indebtedness" means, at a particular date, all Indebtedness, calculated for the Borrower and its Subsidiaries on a consolidated basis.

"Control" means the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of a Person, whether through the ability to exercise voting power, by contract or otherwise. "Controlling" and "Controlled" have meanings correlative thereto.

"Corresponding Tenor" with respect to any Available Tenor means, as applicable, either a tenor (including overnight) or an interest payment period having approximately the same length (disregarding business day adjustment) as such Available Tenor.

"Credit Event" means a Borrowing, the issuance, amendment, renewal or extension of a Letter of Credit, an LC Disbursement or any of the foregoing.

"Credit Party" means the Administrative Agent, each Issuing Bank, the Swingline Lender or any other Lender.

"Daily Simple SOFR" means, for any day (a "SOFR Rate Day"), a rate per annum equal to SOFR for the day (such day "SOFR Determination Date") that is five (5) U.S. Government Securities Business Days prior to (i) if such SOFR Rate Day is a U.S. Government Securities Business Day, such SOFR Rate Day or (ii) if such SOFR Rate Day is not a U.S. Government Securities Business Day, the U.S. Government Securities Business Day immediately preceding such SOFR Rate Day, in each case, as such SOFR is published by the SOFR Administrator on the SOFR Administrator's Website. Any change in Daily Simple SOFR due to a change in SOFR shall be effective from and including the effective date of such change in SOFR without notice to the Borrower.

"Debt Rating" means the rating assigned by S&P or Moody's, as applicable, to the Borrower's senior, unsecured, non-credit enhanced long-term debt; provided that, (a) if the Borrower's senior, unsecured, non-credit enhanced long-term debt is not rated by S&P, "Debt Rating" for S&P shall mean the rating that is one level below the rating assigned by S&P to the Borrower's senior, secured long-term debt and (b) if the Borrower's senior, unsecured, non-credit enhanced long-term debt is not rated by Moody's, "Debt Rating" for Moody's shall mean the rating that is one level below the rating assigned by Moody's to the Borrower's senior, secured long-term debt.

"Default" means any event or condition which constitutes an Event of Default or which upon notice, lapse of time or both would, unless cured or waived, become an Event of Default.

"Defaulting Lender" means any Lender that (a) has failed, within two (2) Business Days of the date required to be funded or paid, to (i) fund any portion of its Loans, (ii) fund any portion of its participations in Letters of Credit or Swingline Loans or (iii) pay over to any Credit Party any other amount required to be paid by it hereunder, unless, in the case of clause (i) above, a condition precedent to funding has not been satisfied or is subject to a good faith dispute and such Lender notifies the Administrative Agent in writing that such Lender has not funded because, in such Lender's good faith determination, such condition precedent to funding (specifically identified and including the particular default, if any) has not been satisfied, (b) has notified the Borrower or any Credit Party in writing, or has made a public statement to the effect, that it does not intend or expect to comply with any of its funding obligations under this Agreement (unless such writing or public statement indicates that such position is based on such Lender's good faith determination that a condition precedent (specifically identified and including the particular default, if any) to funding a Loan under this Agreement cannot be satisfied) or generally under other agreements in which it commits to extend credit, (c) has failed, within three (3) Business Days after request by a Credit Party, acting in good faith, to provide a certification in writing from an authorized officer of such Lender that it will comply with its obligations (and is financially able to meet such obligations) to fund prospective Loans and participations in then outstanding Letters of Credit and Swingline Loans under this Agreement, provided that such Lender shall cease to be a Defaulting Lender pursuant to this clause (c) upon such Credit Party's receipt of such certification in form and substance satisfactory to it and the Administrative Agent, or (d) has become the subject of (A) a Bankruptcy Event or (B) a Bail-In Action.

"Dollars" or "$" refers to lawful money of the United States of America.

"EEA Financial Institution" means (a) any credit institution or investment firm established in any EEA Member Country which is subject to the supervision of an EEA Resolution Authority, (b) any entity established in an EEA Member Country which is a parent of an institution described in clause (a) of this definition, or (c) any financial institution established in an EEA Member Country which is a subsidiary of an institution described in clauses (a) or (b) of this definition and is subject to consolidated supervision with its parent.

"EEA Member Country" means any of the member states of the European Union, Iceland, Liechtenstein, and Norway.

"EEA Resolution Authority" means any public administrative authority or any Person entrusted with public administrative authority of any EEA Member Country (including any delegee) having responsibility for the resolution of any EEA Financial Institution.

"Electronic Signature" means an electronic sound, symbol, or process attached to, or associated with, a contract or other record and adopted by a Person with the intent to sign, authenticate or accept such contract or record.

"Environmental Laws" means all laws, rules, regulations, codes, ordinances, orders, decrees, judgments, injunctions, notices or binding agreements issued, promulgated or entered into by any Governmental Authority, relating in any way to (i) the environment, (ii) preservation or reclamation of natural resources, (iii) the management, release or threatened release of any Hazardous Material or (iv) health and safety matters.

"Environmental Liability" means any liability, contingent or otherwise (including any liability for damages, costs of environmental remediation, fines, penalties or indemnities), of the Borrower or any Subsidiary directly or indirectly resulting from or based upon (a) violation of any Environmental Law, (b) the generation, use, handling, transportation, storage, treatment or disposal of any Hazardous Materials, (c) exposure to any Hazardous Materials, (d) the release or threatened release of any Hazardous Materials into the environment or (e) any contract, agreement or other consensual arrangement pursuant to which liability is assumed or imposed with respect to any of the foregoing.

"Equity Interests" means shares of capital stock, partnership interests, membership interests in a limited liability company, beneficial interests in a trust or other equity ownership interests in a Person, and any warrants, options or other rights entitling the holder thereof to purchase or acquire any such equity interest, but excluding any debt securities convertible into any of the foregoing.

"ERISA" means the Employee Retirement Income Security Act of 1974, as amended from time to time, and the rules and regulations promulgated thereunder.

"ERISA Affiliate" means any trade or business (whether or not incorporated) that, together with the Borrower, is treated as a single employer under Section 414(b) or (c) of the Code or Section 4001(b)(1) of ERISA or, solely for purposes of Section 302 of ERISA and Section 412 of the Code, is treated as a single employer under Section 414 of the Code.

"ERISA Event" means (a) any Reportable Event; (b) the failure to satisfy the "minimum funding standard" (as defined in Section 412 of the Code or Section 302 of ERISA), whether or not waived; (c) the filing pursuant to Section 412(c) of the Code or Section 302(c) of ERISA of an application for a waiver of the minimum funding standard with respect to any Plan; (d) the incurrence by the Borrower or any of its ERISA Affiliates of any liability under Title IV of ERISA with respect to the termination of any Plan; (e) the receipt by the Borrower or any ERISA Affiliate from the PBGC or a plan administrator of any notice relating to an intention to terminate any Plan or Plans or to appoint a trustee to administer any Plan; (f) the incurrence by the Borrower or any of its ERISA Affiliates of any liability with respect to the withdrawal or partial withdrawal of the Borrower or any of its ERISA Affiliates from any Plan or Multiemployer Plan; or (g) the receipt by the Borrower or any ERISA Affiliate of any notice, or the receipt by any Multiemployer Plan from the Borrower or any ERISA Affiliate of any notice, concerning the imposition upon the Borrower or any of its ERISA Affiliates of Withdrawal Liability or a determination that a Multiemployer Plan is, or is expected to be, insolvent or in reorganization, within the meaning of Title IV of ERISA.

"EU Bail-In Legislation Schedule" means the EU Bail-In Legislation Schedule published by the Loan Market Association (or any successor Person), as in effect from time to time.

"Event of Default" has the meaning assigned to such term in Section 7.01.

"Excluded Taxes" means any of the following Taxes imposed on or with respect to a Recipient or required to be withheld or deducted from a payment to a Recipient, (a) Taxes imposed on or measured by net income (however denominated), gross receipts, franchise Taxes, and branch profits Taxes, in each case, (i) imposed as a result of such Recipient being organized under the laws of, or having its principal office or, in the case of any Lender, its applicable lending office located in, the jurisdiction imposing such Tax (or any political subdivision thereof) or (ii) that are Other Connection Taxes, (b) in the case of a Lender, U.S. Federal withholding Taxes imposed on amounts payable to or for the account of such Lender with respect to an applicable interest in a Loan, Letter of Credit or Commitment pursuant to a law in effect on the date on which (i) such Lender acquires such interest in the Loan, Letter of Credit or Commitment (other than pursuant to an assignment request by the Borrower under Section 2.19(b)) or (ii) such Lender changes its lending office, except in each case to the extent that, pursuant to Section 2.17, amounts with respect to such Taxes were payable either to such Lender's assignor immediately before such Lender acquired the applicable interest in a Loan, Letter of Credit or Commitment or to such Lender immediately before it changed its lending office, (c) Taxes attributable to such Recipient's failure to comply with Section 2.17(f) and (d) any withholding Taxes imposed under FATCA.

"Existing Credit Agreement" has the meaning assigned to it in the Recitals to this Agreement.

"Existing Maturity Date" has the meaning assigned to such term in Section 2.22(a).

"Extending Lender" has the meaning assigned to such term in Section 2.22(b)(ii).

"Extension Request" means a written request from the Borrower to the Administrative Agent requesting an extension of the Maturity Date pursuant to Section 2.22.

"FATCA" means Sections 1471 through 1474 of the Code, as of the date of this Agreement (or any amended or successor version that is substantively comparable and not materially more onerous to comply with), any current or future regulations or official interpretations thereof, any agreement entered into pursuant to Section 1471(b)(1) of the Code and any fiscal or regulatory legislation, rules or practices adopted pursuant to any intergovernmental agreement, treaty or convention among Governmental Authorities and implementing such Sections of the Code.

"Federal Funds Effective Rate" means, for any day, the rate calculated by the NYFRB based on such day's federal funds transactions by depositary institutions, as determined in such manner as shall be set forth on the NYFRB's Website from time to time, and published on the next succeeding Business Day by the NYFRB as the effective federal funds rate; provided that if the Federal Funds Effective Rate as so determined would be less than zero, such rate shall be deemed to be zero for the purposes of this Agreement.

"Federal Reserve Board" means the Board of Governors of the Federal Reserve System of the United States of America.

"Financial Officer" means the chief financial officer, principal accounting officer, treasurer or controller of the Borrower.

"Fitch" means Fitch, Inc., doing business as Fitch Ratings.

"Floor" means the benchmark rate floor, if any, provided in this Agreement initially (as of the execution of this Agreement, the modification, amendment or renewal of this Agreement or otherwise) with respect to the Adjusted Term SOFR Rate or the Adjusted Daily Simple SOFR, as applicable. For the avoidance of doubt, the initial Floor for each of Adjusted Term SOFR Rate or the Adjusted Daily Simple SOFR shall be 0%.

"Foreign Lender" means (a) if the Borrower is a U.S. Person, a Lender that is not a U.S. Person, and (b) if the Borrower is not a U.S. Person, a Lender that is resident or organized under the laws of a jurisdiction other than that in which the Borrower is resident for tax purposes.

"GAAP" means generally accepted accounting principles in the United States of America in effect from time to time.

"Governmental Authority" means the government of the United States of America, any other nation or any political subdivision thereof, whether state or local, and any agency, authority, instrumentality, regulatory body, court, central bank or other entity exercising executive, legislative, judicial, taxing, regulatory or administrative powers or functions of or pertaining to government.

"Hazardous Materials" means all explosive or radioactive substances or wastes and all hazardous or toxic substances, wastes or other pollutants, including petroleum or petroleum distillates, asbestos or asbestos containing materials, polychlorinated biphenyls, radon gas, infectious or medical wastes and all other substances or wastes of any nature regulated pursuant to any Environmental Law.

"Holdings" means Northwest Natural Holding Company, an Oregon corporation.

"Hostile Acquisition" means (a) the acquisition of the Equity Interests of a Person through a tender offer or similar solicitation of the owners of such Equity Interests which has not been approved (prior to such acquisition) by the board of directors (or any other applicable governing body) of such Person or by similar action if such Person is not a corporation and (b) any such acquisition as to which such approval has been withdrawn.

"Hybrid Securities" means debt or equity securities that meet the following requirements: (a) such securities are issued by (i) the Borrower or (ii) a Subsidiary or an independent trust (a "Hybrid Securities Subsidiary") that engages in no business other than the issuance of such securities and lending the proceeds thereof to the Borrower; (b) each of such securities of the Borrower and the loans, if any, made to the Borrower by the applicable Hybrid Securities Subsidiary with the proceeds of such securities (i) are subordinated to the payment by the Borrower of its obligations hereunder in a manner reasonably satisfactory to the Administrative Agent and (ii) require no repayment, prepayment, mandatory redemption or mandatory repurchase prior to the date that is at least 91 days after the scheduled Maturity Date; and (c) such securities are classified as possessing a minimum of at least one of the following: (x) "intermediate equity content" by S&P, (y) "Basket C equity credit" by Moody's and (z) "50% equity credit" by Fitch.

"Increasing Lender" has the meaning assigned to such term in Section 2.20.

"Incremental Term Loan" has the meaning assigned to such term in Section 2.20.

"Incremental Term Loan Amendment" has the meaning assigned to such term in Section 2.20.

"Indebtedness" of a Person means, at a particular date, the sum (without duplication) at such date of (a) indebtedness for borrowed money or for the deferred purchase price of property, goods or services, excluding (i) trade accounts payable arising in the ordinary course of business, (ii) pension liabilities that are not then due and payable and (iii) obligations in respect of Hybrid Securities that are not then due and payable, (b) obligations of such Person under capitalized leases and synthetic leases, (c) debts of third persons guaranteed by such Person or secured by property of such Person (provided that the amount of Indebtedness secured by property of such Person shall be the lesser of (x) the fair market value of such property as of the date of determination and (y) the amount of the Indebtedness as of the date of determination) and (d) any non-contingent reimbursement obligations of such Person in respect of letters of credit, acceptances or similar obligations issued or created for the account of such Person.

"Indemnified Taxes" means (a) Taxes, other than Excluded Taxes, imposed on or with respect to any payment made by or on account of any obligation of the Borrower under any Loan Document and (b) to the extent not otherwise described in clause (a) hereof, Other Taxes.

"Indemnitee" has the meaning assigned to it in Section 9.03(b).

"Ineligible Institution" has the meaning assigned to such term in Section 9.04(b).

"Information" has the meaning assigned to it in Section 9.12.

"Information Memorandum" means the Confidential Information Memorandum dated October 13, 2021 relating to the Borrower and the Transactions.

"Interest Election Request" means a request by the Borrower to convert or continue a Revolving Borrowing in accordance with Section 2.08, which shall be substantially in the form attached hereto as Exhibit F-2 or any other form approved by the Administrative Agent.

"Interest Payment Date" means (a) with respect to any ABR Loan (other than a Swingline Loan), the second Business Day following the last day of each March, June, September and December and the Maturity Date, (b) with respect to any Term Benchmark Loan, the last day of each Interest Period applicable to the Borrowing of which such Loan is a part and, in the case of a Term Benchmark Borrowing with an Interest Period of more than three months' duration, each day prior to the last day of such Interest Period that occurs at intervals of three months' duration after the first day of such Interest Period and the Maturity Date, (c) with respect to any Swingline Loan, the day that such Loan is required to be repaid and the Maturity Date and (d) with respect to any RFR Loan, (1) each date that is on the numerically corresponding day in each calendar month that is one month after the Borrowing of such Loan (or, if there is no such numerically corresponding day in such month, then the last day of such month) and (2) the Maturity Date.

"Interest Period" means, with respect to any Term Benchmark Borrowing, the period commencing on the date of such Borrowing and ending on the numerically corresponding day in the calendar month that is one, three or six months thereafter (in each case, subject to the availability for the Benchmark applicable to the relevant Loan or Commitment), as the Borrower may elect; provided, that (i) if any Interest Period would end on a day other than a Business Day, such Interest Period shall be extended to the next succeeding Business Day unless such next succeeding Business Day would fall in the next calendar month, in which case such Interest Period shall end on the next preceding Business Day, (ii) any Interest Period that commences on the last Business Day of a calendar month (or on a day for which there is no numerically corresponding day in the last calendar month of such Interest Period) shall end on the last Business Day of the last calendar month of such Interest Period, and (iii) no tenor that has been removed from this definition pursuant to Section 2.14(e) shall be available for specification in such Borrowing Request or Interest Election Request. For purposes hereof, the date of a Borrowing initially shall be the date on which such Borrowing is made and, in the case of a Revolving Borrowing, thereafter shall be the effective date of the most recent conversion or continuation of such Borrowing.

"Investment Grade Rating" means, for S&P, Fitch or Moody's, as applicable, (a) if such rating agency has a rating assigned to the Borrower's senior, unsecured, non-credit enhanced long-term debt of BBB- or higher by S&P or Fitch and Baa3 or higher by Moody's; and (b) if such rating agency does not have a rating assigned to the Borrower's senior, unsecured, non-credit enhanced long-term debt but has a rating assigned to the Borrower's senior, secured long-term debt, BBB or higher by S&P or Fitch and Baa2 or higher by Moody's.

"IRS" means the United States Internal Revenue Service.

"Issuing Bank" means JPMorgan Chase Bank, N.A., Bank of America, N.A., U.S. Bank National Association and Wells Fargo Bank, National Association and any other Lender that agrees to act as an Issuing Bank (in each case, through itself or through one of its designated Affiliates or branch offices), each in its capacity as the issuer of Letters of Credit hereunder, and its successors in such capacity as provided in Section 2.06(i). Any Issuing Bank may, in its discretion, arrange for one or more Letters of Credit to be issued by Affiliates of such Issuing Bank, in which case the term "Issuing Bank" shall include any such Affiliate with respect to Letters of Credit issued by such Affiliate. Each reference herein to the "Issuing Bank" in connection with a Letter of Credit or other matter shall be deemed to be a reference to the relevant Issuing Bank with respect thereto.

"KPI Metric" means each of the Carbon Savings KPI and the Transmission Pipeline Inspection KPI.

"KPI Metric Calculation Methodology" means the Carbon Savings KPI Metric Calculation Methodology and the Transmission Pipeline Inspection KPI Calculation Methodology.

"KPI Metrics Report" means an annual report (it being understood that this annual report may take the form of the annual Sustainability Report) that sets forth the calculations for each KPI Metric for a specific Reference Year. The Sustainability Assurance Provider shall attest to the KPI Metrics for verification of the method of calculation of each KPI Metric in conformity with the applicable KPI Metric Calculation Methodology.

"LC Collateral Account" has the meaning assigned to such term in Section 2.06(j).

"LC Disbursement" means a payment made by an Issuing Bank pursuant to a Letter of Credit.

"LC Exposure" means, at any time, the sum of (a) the aggregate undrawn amount of all outstanding Letters of Credit at such time plus (b) the aggregate amount of all LC Disbursements that have not yet been reimbursed by or on behalf of the Borrower at such time. The LC Exposure of any Lender at any time shall be its Applicable Percentage of the total LC Exposure at such time. For all purposes of this Agreement, if on any date of determination a Letter of Credit has expired by its terms but any amount may still be drawn thereunder by reason of the operation of Article 29(a) of the Uniform Customs and Practice for Documentary Credits, International Chamber of Commerce Publication No. 600 (or such later version thereof as may be in effect at the applicable time) or Rule 3.13 or Rule 3.14 of the International Standby Practices, International Chamber of Commerce Publication No. 590 (or such later version thereof as may be in effect at the applicable time) or similar terms of the Letter of Credit itself, or if compliant documents have been presented but not yet honored, such Letter of Credit shall be deemed to be "outstanding" and "undrawn" in the amount so remaining available to be paid, and the obligations of the Borrower and each Lender shall remain in full force and effect until the Issuing Banks and the Lenders shall have no further obligations to make any payments or disbursements under any circumstances with respect to any Letter of Credit.

"Lender Parent" means, with respect to any Lender, any Person as to which such Lender is, directly or indirectly, a subsidiary.

"Lender-Related Person" has the meaning assigned to it in Section 9.03(d).

"Lenders" means the Persons listed on Schedule 2.01A and any other Person that shall have become a party hereto pursuant to an Assignment and Assumption or otherwise, other than any such Person that ceases to be a party hereto pursuant to an Assignment and Assumption or otherwise. Unless the context otherwise requires, the term "Lenders" includes the Swingline Lender and the Issuing Banks.

"Letter of Credit" means any letter of credit issued pursuant to this Agreement.

"Letter of Credit Agreement" has the meaning assigned to it in Section 2.06(b).

"Letter of Credit Commitment" means, with respect to each Issuing Bank, the commitment of such Issuing Bank to issue Letters of Credit hereunder. The initial amount of each Issuing Bank's Letter of Credit Commitment is set forth on Schedule 2.01B, or if an Issuing Bank has entered into an Assignment and Assumption or has otherwise assumed a Letter of Credit Commitment after the Restatement Effective Date, the amount set forth for such Issuing Bank as its Letter of Credit Commitment in the Register maintained by the Administrative Agent. The Letter of Credit Commitment of an Issuing Bank may be modified from time to time by agreement between such Issuing Bank and the Borrower, and notified to the Administrative Agent.

"Liabilities" means any losses, claims (including intraparty claims), demands, damages or liabilities of any kind.

"Loan Documents" means this Agreement, including schedules and exhibits hereto, and any agreements entered into in connection herewith by the Borrower with or in favor of the Administrative Agent and/or the Lenders, including any promissory notes issued pursuant to Section 2.10(e), any amendments, modifications or supplements thereto or waivers thereof, UCC filings, letter of credit applications and any agreements between the Borrower and an Issuing Bank regarding the issuance by such Issuing Bank of Letters of Credit hereunder and/or the respective rights and obligations between the Borrower and such Issuing Bank in connection thereunder and any other documents instruments or certificates delivered by the Borrower pursuant to the terms of any other Loan Document. Any reference in this Agreement or any other Loan Document to a Loan Document shall include all appendices, exhibits or schedules thereto, and all amendments, restatements, supplements or other modifications thereto, and shall refer to this Agreement or such Loan Document as the same may be in effect at any and all times such reference becomes operative.

"Loans" means the loans made by the Lenders to the Borrower pursuant to this Agreement.

"Margin Stock" means margin stock within the meaning of Regulations T, U and X, as applicable.

"Material Adverse Effect" means a material adverse effect on (a) the operations, the business or financial condition of the Borrower and its Subsidiaries taken as a whole, (b) the ability of the Borrower to perform any of its Obligations or (c) the validity or enforceability of this Agreement or any and all other Loan Documents or the rights or remedies of the Administrative Agent and the Lenders thereunder.

"Maturity Date" means, with respect to any Lender, the later of (a) November 3, 2026 and (b) if the maturity date is extended for such Lender pursuant to Section 2.22, such extended maturity date as determined pursuant to such Section; *provided*, *however*, in each case, if such date is not a Business Day, the Maturity Date shall be the next preceding Business Day.

"Maximum Rate" has the meaning assigned to it in Section 9.16.

"Moody's" means Moody's Investors Service, Inc.

"Multiemployer Plan" means a multiemployer plan as defined in Section 4001(a)(3) of ERISA.

"Non-extending Lender" has the meaning assigned to such term in Section 2.22(a).

"NYFRB" means the Federal Reserve Bank of New York.

"NYFRB's Website" means the website of the NYFRB at http://www.newyorkfed.org or any successor source.

"NYFRB Rate" means, for any day, the greater of (a) the Federal Funds Effective Rate in effect on such day and (b) the Overnight Bank Funding Rate in effect on such day (or for any day that is not a Business Day, for the immediately preceding Business Day); provided that if none of such rates are published for any day that is a Business Day, the term "NYFRB Rate" means the rate for a federal funds transaction quoted at 11:00 a.m. on such day received by the Administrative Agent from a federal funds broker of recognized standing selected by it; provided, further, that if any of the aforesaid rates as so determined would be less than zero, such rate shall be deemed to be zero for purposes of this Agreement.

"Obligations" means all advances to, and debts, liabilities, obligations, covenants and duties of, the Borrower and its Subsidiaries arising under any Loan Document or otherwise with respect to any Loan or Letter of Credit, whether direct or indirect (including those acquired by assumption), absolute or contingent, due or to become due, now existing or hereafter arising and including interest and fees that accrue after the commencement by or against the Borrower or any Affiliate thereof of any proceeding under any debtor relief laws naming such Person as the debtor in such proceeding, regardless of whether such interest and fees are allowed or allowable claims in such proceeding. Without limiting the foregoing, the Obligations include (a) the obligation to pay principal, interest, Letter of Credit commissions, charges, expenses, fees, indemnities and other amounts payable by the Borrower under any Loan Document and (b) the obligation of the Borrower to reimburse any amount in respect of any of the foregoing that the Administrative Agent or any Lender, in each case in its sole discretion, may elect to pay or advance on behalf of the Borrower.

"OFAC" means the Office of Foreign Assets Control of the U.S. Department of the Treasury.

"Other Connection Taxes" means, with respect to any Recipient, Taxes imposed as a result of a present or former connection between such Recipient and the jurisdiction imposing such Tax (other than connections arising from such Recipient having executed, delivered, become a party to, performed its obligations under, received payments under, received or perfected a security interest under, engaged in any other transaction pursuant to or enforced any Loan Document, or sold or assigned an interest in any Loan, Letter of Credit or Loan Document).

"Other Taxes" means all present or future stamp, court or documentary, intangible, recording, filing or similar Taxes that arise from any payment made under, from the execution, delivery, performance, enforcement or registration of, from the receipt or perfection of a security interest under, or otherwise with respect to, any Loan Document, except any such Taxes that are Other Connection Taxes imposed with respect to an assignment (other than an assignment made pursuant to Section 2.19).

"Overnight Bank Funding Rate" means, for any day, the rate comprised of both overnight federal funds and overnight eurodollar transactions denominated in Dollars by U.S.-managed banking offices of depository institutions, as such composite rate shall be determined by the NYFRB as set forth on the NYFRB's Website from time to time, and published on the next succeeding Business Day by the NYFRB as an overnight bank funding rate.

"Participant" has the meaning assigned to such term in Section 9.04(c).

"Participant Register" has the meaning assigned to such term in Section 9.04(c).

"Patriot Act" has the meaning assigned to such term in Section 9.14.

"Payment" has the meaning assigned to such term in Section 8.06(c).

"Payment Notice" has the meaning assigned to such term in Section 8.06(c).

"PBGC" means the Pension Benefit Guaranty Corporation referred to and defined in ERISA and any successor entity performing similar functions.

"Person" means any natural person, corporation, limited liability company, trust, joint venture, association, company, partnership, Governmental Authority or other entity.

"Plan" means any employee pension benefit plan (other than a Multiemployer Plan) subject to the provisions of Title IV of ERISA or Section 412 of the Code or Section 302 of ERISA, and in respect of which the Borrower or any ERISA Affiliate is (or, if such plan were terminated, would under Section 4069 of ERISA be deemed to be) an "employer" as defined in Section 3(5) of ERISA.

"Plan Asset Regulations" means 29 CFR § 2510.3-101 et seq., as modified by Section 3(42) of ERISA.

"Platform" has the meaning assigned to such term in Section 5.02.

"Pricing Certificate" means a certificate executed by the chief executive officer, chief financial officer, treasurer, controller or any vice president of the Borrower and attaching (a) true and correct copies of the KPI Metrics Report for the most recently ended Reference Year and setting forth the Sustainability Rate Adjustment and the Sustainability Facility Fee Adjustment for the period covered thereby and computations in reasonable detail in respect thereof and (b) a review report of the Sustainability Assurance Provider confirming that the Sustainability Assurance Provider is not aware of any modifications that should be made to such computations in order for them to be presented in all material respects in conformity with the KPI Metric Calculation Methodology.

"Pricing Certificate Inaccuracy" has the meaning assigned to such term in Section 1.08(d).

"Prime Rate" means the rate of interest last quoted by The Wall Street Journal as the "Prime Rate" in the U.S. or, if The Wall Street Journal ceases to quote such rate, the highest per annum interest rate published by the Federal Reserve Board in Federal Reserve Statistical Release H.15 (519) (Selected Interest Rates) as the "bank prime loan" rate or, if such rate is no longer quoted therein, any similar rate quoted therein (as determined by the Administrative Agent) or any similar release by the Federal Reserve Board (as determined by the Administrative Agent). Each change in the Prime Rate shall be effective from and including the date such change is publicly announced or quoted as being effective.

"Proceeding" means any claim, litigation, investigation, action, suit, arbitration or administrative, judicial or regulatory action or proceeding in any jurisdiction.

"PTE" means a prohibited transaction class exemption issued by the U.S. Department of Labor, as any such exemption may be amended from time to time.

"Public Lender" has the meaning assigned to such term in Section 5.02.

"Recipient" means (a) the Administrative Agent, (b) any Lender and (c) any Issuing Bank, as applicable.

"Reference Time" with respect to any setting of the then-current Benchmark means (1) if such Benchmark is the Term SOFR Rate, 5:00 a.m. (Chicago time) on the day that is two (2) U.S. Government Securities Business Days preceding the date of such setting, (2) if, following a Benchmark Transition Event and Benchmark Replacement Date with respect to the Term SOFR Rate, such Benchmark is Daily Simple SOFR, then four (4) Business Days prior to such setting and (3) if such Benchmark is not the Term SOFR Rate or Daily Simple SOFR, the time determined by the Administrative Agent in its reasonable discretion.

"Reference Year" means, with respect to any Pricing Certificate, the fiscal year ending immediately prior to the date of such Pricing Certificate.

"Register" has the meaning assigned to such term in Section 9.04(b).

"Regulation D" means Regulation D of the Federal Reserve Board, as in effect from time to time and all official rulings and interpretations thereunder or thereof.

"Regulation T" means Regulation T of the Federal Reserve Board, as in effect from time to time and all official rulings and interpretations thereunder or thereof.

"Regulation U" means Regulation U of the Federal Reserve Board, as in effect from time to time and all official rulings and interpretations thereunder or thereof.

"Regulation X" means Regulation X of the Federal Reserve Board, as in effect from time to time and all official rulings and interpretations thereunder or thereof.

"Related Parties" means, with respect to any specified Person, such Person's Affiliates and the respective directors, officers, employees, agents, advisors and representatives of such Person and such Person's Affiliates.

"Relevant Governmental Body" means the Federal Reserve Board and/or the NYFRB, or a committee officially endorsed or convened by the Federal Reserve Board or the NYFRB, or, in each case, any successor thereto.

"Relevant Rate" means (i) with respect to any Term Benchmark Borrowing, the Adjusted Term SOFR Rate or (ii) with respect to any RFR Borrowing following a Benchmark Transition Event and Benchmark Replacement Date with respect to the Term SOFR Rate, Adjusted Daily Simple SOFR, as applicable.

"Reportable Event" means a reportable event, as defined in Section 4043 of ERISA and the regulations issued under such section, with respect to a Plan, excluding any event as to which the PBGC by regulation waived the requirements of Section 4043(a) of ERISA that it be notified within 30 days of the occurrence of such event, provided that a failure to meet the minimum funding standard of Section 412 of the Code and of Section 302 of ERISA shall be a Reportable Event regardless of the issuance of any such waiver of the notice requirement in accordance with either Section 4043(a) of ERISA or Section 412(c) of the Code.

"Replacement Lender" has the meaning assigned to such term in Section 2.22(c).

"Required Filings" means (a) the filing made by the Borrower on or about October 4, 2021 with the Oregon Public Utility Commission, requesting approval of this Agreement, which was obtained by Order No. 21-335 of such Commission entered October 21, 2021, and (b) the notice filing made by the Borrower on or about October 25, 2021 with the Washington Utilities and Transportation Commission.

"Required Lenders" means, subject to Section 2.21, at any time, Lenders having Revolving Credit Exposures and unused Commitments representing more than 50% of the sum of the Total Revolving Credit Exposure and unused Commitments at such time; provided that, for purposes of declaring the Loans to be due and payable pursuant to Section 7.01, and for all purposes after the Loans become due and payable pursuant to Section 7.01 or the Commitments expire or terminate, then, as to each Lender, clause (a) of the definition of Swingline Exposure shall only be applicable for purposes of determining the Revolving Credit Exposure of such Lender to the extent such Lender shall have funded its participation in the outstanding Swingline Loans.

"Requirement of Law" means, as to any Person, the certificate of incorporation and bylaws or other organizational or governing documents of such Person, and any law, treaty, rule or regulation or order or determination of an arbitrator or a court or other Governmental Authority, in each case applicable to or binding upon such Person or any of its property or to which such Person or any of its property is subject.

"Resolution Authority" means an EEA Resolution Authority or, with respect to any UK Financial Institution, a UK Resolution Authority.

"Response Date" has the meaning assigned to such term in Section 2.22(a).

"Responsible Officer" means the chief executive officer, the president, any senior vice president, the chief financial officer, the chief accounting officer, the treasurer or the general counsel of the Borrower.

"Restatement Effective Date" means the date on which the conditions specified in Section 4.01 are satisfied (or waived in accordance with Section 9.02).

"Revolving Credit Exposure" means, with respect to any Lender at any time, the sum of the outstanding principal amount of such Lender's Revolving Loans, its LC Exposure and its Swingline Exposure at such time.

"Revolving Loan" means a Loan made pursuant to Section 2.03.

"RFR Borrowing" means, as to any Borrowing, the RFR Loans comprising such Borrowing.

"RFR Loan" means a Loan that bears interest at a rate based on the Adjusted Daily Simple SOFR.

"S&P" means Standard & Poor's Ratings Services, a Standard & Poor's Financial Services LLC business.

"Sanctioned Country" means, at any time, a country, region or territory (other than the United States or any region or territory therein) which is itself the subject or target of any Sanctions (at the time of this Agreement, the so-called Donetsk People's Republic, the so-called Luhansk People's Republic, the Crimea Region of Ukraine, Cuba, Iran, North Korea and Syria).

"Sanctioned Person" means, at any time, (a) any Person listed in any Sanctions-related list of designated Persons maintained by OFAC, the U.S. Department of State, the United Nations Security Council, the European Union, any European Union member state, His Majesty's Treasury of the United Kingdom, or other relevant sanctions authority, (b) any Person operating, organized or resident in a Sanctioned Country, (c) any Person owned or controlled by any such Person or Persons described in the foregoing clauses (a) or (b), or (d) any Person otherwise the subject of any Sanctions.

"Sanctions" means all economic or financial sanctions or trade embargoes imposed, administered or enforced from time to time by (a) the U.S. government, including those administered by OFAC or the U.S. Department of State, or (b) the United Nations Security Council, the European Union, any European Union member state, His Majesty's Treasury of the United Kingdom or other relevant sanctions authority.

"SEC" means the Securities and Exchange Commission of the United States of America.

"Securities Act" means the United States Securities Act of 1933.

"Significant Subsidiary" means a Subsidiary that is a "significant subsidiary" as that term is defined in Rule 1-02(w) of Regulation S-X promulgated by the SEC (as in effect on the Restatement Effective Date).

"SOFR" means, a rate equal to the secured overnight financing rate as administered by the SOFR Administrator.

"SOFR Administrator" means the NYFRB (or a successor administrator of the secured overnight financing rate).

"SOFR Administrator's Website" means the NYFRB's Website, currently at http://www.newyorkfed.org, or any successor source for the secured overnight financing rate identified as such by the SOFR Administrator from time to time.

"SOFR Determination Date" has the meaning specified in the definition of "Daily Simple SOFR".

"SOFR Rate Day" has the meaning specified in the definition of "Daily Simple SOFR".

"subsidiary" means, with respect to any Person (the "parent") at any date, any corporation, limited liability company, partnership, association or other entity (a) of which securities or other ownership interests representing more than 50% of the equity or more than 50% of the ordinary voting power or, in the case of a partnership, more than 50% of the general partnership interests are, as of such date, owned, Controlled or held, or (b) that is, as of such date, otherwise Controlled, by the parent and/or one or more subsidiaries of the parent.

"Subsidiary" means any subsidiary of the Borrower.

"Sustainability Assurance Provider" means PricewaterhouseCoopers LLP, or any replacement sustainability assurance provider thereof as designated from time to time by the Borrower; provided, that, any such replacement Sustainability Assurance Provider (a) shall be (i) a qualified external reviewer, independent of Holdings and its Subsidiaries, with relevant expertise, such as an auditor, environmental consultant and/or independent ratings agency of recognized national standing or (ii) another firm designated by the Borrower and approved by the Required Lenders, and (b) shall apply substantially the same attestation standards and methodology used in the KPI Metric Calculation Methodologies, except for any changes to such standards and/or methodology that are approved by the Borrower and either (x) are consistent with then generally accepted industry standards or (y) if not so consistent, are approved by the Required Lenders.

"Sustainability Facility Fee Adjustment" means, with respect to any KPI Metrics Report for any period between Sustainability Pricing Adjustment Dates, an amount (whether positive, negative or zero), expressed as a percentage, equal to the sum of (a) the Carbon Savings KPI Facility Fee Adjustment Amount (whether positive, negative or zero), plus (b) the Transmission Pipeline Inspection KPI Facility Fee Adjustment Amount (whether positive, negative or zero), in each case for such period.

"Sustainability Pricing Adjustment Date" has the meaning specified in Section 1.08(a).

"Sustainability Rate Adjustment" with respect to any KPI Metrics Report for any period between Sustainability Pricing Adjustment Dates, an amount (whether positive, negative or zero), expressed as a percentage, equal to the sum of (a) the Carbon Savings KPI Applicable Rate Adjustment Amount (whether positive, negative or zero), plus (b) the Transmission Pipeline Inspection KPI Applicable Rate Adjustment Amount (whether positive, negative or zero), in each case for such period.

"Sustainability Report" means the annual non-financial disclosure report reported by the Borrower (it being understood that this report may take the form of Holdings' annual Environmental, Social and Governance Report, a separate sustainability report or a separate report regarding only the KPI Metrics) and published on an Internet or intranet website to which each Lender and the Administrative Agent have been granted access free of charge (or at the expense of the Borrower).

"Sustainability Structuring Agent" means J.P. Morgan Securities LLC, in its capacity as sustainability structuring agent hereunder.

"Sustainability Table" means the Sustainability Table set forth on Schedule 1.08 hereto.

"Swap Agreement" means any agreement with respect to any swap, forward, future or derivative transaction or option or similar agreement involving, or settled by reference to, one or more rates, currencies, commodities, equity or debt instruments or securities, or economic, financial or pricing indices or measures of economic, financial or pricing risk or value or any similar transaction or any combination of these transactions; provided that no phantom stock or similar plan providing for payments only on account of services provided by current or former directors, officers, employees or consultants of the Borrower or the Subsidiaries shall be a Swap Agreement.

"Swingline Exposure" means, at any time, the aggregate principal amount of all Swingline Loans outstanding at such time. The Swingline Exposure of any Lender at any time shall be the sum of (a) its Applicable Percentage of the total Swingline Exposure at such time other than with respect to any Swingline Loans made by such Lender in its capacity as a Swingline Lender and (b) the aggregate principal amount of all Swingline Loans made by such Lender as a Swingline Lender outstanding at such time (less the amount of participations funded by the other Lenders in such Swingline Loans).

"Swingline Lender" means JPMorgan Chase Bank, N.A., in its capacity as lender of Swingline Loans hereunder.

"Swingline Loan" means a Loan made pursuant to Section 2.05.

"Taxes" means all present or future taxes, levies, imposts, duties, deductions, withholdings (including backup withholding), value added taxes, or any other goods and services, use or sales taxes, assessments, fees or other charges imposed by any Governmental Authority, including any interest, additions to tax or penalties applicable thereto.

"Term Benchmark" when used in reference to any Loan or Borrowing, refers to whether such Loan, or the Loans comprising such Borrowing, are bearing interest at a rate determined by reference to the Adjusted Term SOFR Rate.

"Term SOFR Determination Day" has the meaning assigned to it under the definition of Term SOFR Reference Rate.

"Term SOFR Rate" means, with respect to any Term Benchmark Borrowing and for any tenor comparable to the applicable Interest Period, the Term SOFR Reference Rate at approximately 5:00 a.m., Chicago time, two U.S. Government Securities Business Days prior to the commencement of such tenor comparable to the applicable Interest Period, as such rate is published by the CME Term SOFR Administrator.

"Term SOFR Reference Rate" means, for any day and time (such day, the "Term SOFR Determination Day"), with respect to any Term Benchmark Borrowing and for any tenor comparable to the applicable Interest Period, the rate per annum published by the CME Term SOFR Administrator and identified by the Administrative Agent as the forward-looking term rate based on SOFR. If by 5:00 pm (New York City time) on such Term SOFR Determination Day, the "Term SOFR Reference Rate" for the applicable tenor has not been published by the CME Term SOFR Administrator and a Benchmark Replacement Date with respect to the Term SOFR Rate has not occurred, then so long as such day is otherwise a U.S. Government Securities Business Day, the Term SOFR Reference Rate for such Term SOFR Determination Day will be the Term SOFR Reference Rate as published in respect of the first preceding U.S. Government Securities Business Day for which such Term SOFR Reference Rate was published by the CME Term SOFR Administrator, so long as such first preceding U.S. Government Securities Business Day is not more than five (5) U.S. Government Securities Business Days prior to such Term SOFR Determination Day.

"Total Capitalization" means the sum of Indebtedness, Equity Interests, additional paid-in capital and retained earnings of the Borrower and its Subsidiaries, taken on a consolidated basis after eliminating all intercompany items.

"Total Revolving Credit Exposure" means the sum of the outstanding principal amount of all Lenders' Revolving Loans, their LC Exposure and their Swingline Exposure at such time; provided, that, clause (a) of the definition of Swingline Exposure shall only be applicable to the extent Lenders shall have funded their respective participations in the outstanding Swingline Loans.

"Transactions" means the execution and delivery by the Borrower of, and the performance by the Borrower of its obligations under, this Agreement and the other Loan Documents, the borrowing of Loans and other credit extensions, the use of the proceeds thereof and the issuance of Letters of Credit hereunder.

"Transmission Pipeline Inspection KPI" means miles of the Borrower's transmission pipeline that are inspected using the in-line inspection approach, as determined and calculated by the Borrower using the Transmission Pipeline Inspection KPI Calculation Methodology.

"Transmission Pipeline Inspection KPI Calculation Methodology" means the calculation methodology used by the Borrower to report 42 miles of transmission pipeline inspected in the Borrower's U.S. DOT PHMSA Annual Report for the calendar year 2020, a copy of which report has been delivered to the Administrative Agent, the Sustainability Structuring Agent and the Lenders prior to the Closing Date, and as identified in the Baseline column of the Sustainability Table.

"Transmission Pipeline Inspection KPI Applicable Rate Adjustment Amount" means, with respect to any period between Sustainability Pricing Adjustment Dates, (a) positive 0.020%, if the Transmission Pipeline Inspection KPI for such period as set forth in the KPI Metrics Report is less than the Transmission Pipeline Inspection KPI Threshold B for such period, (b) 0.000%, if the Transmission Pipeline Inspection KPI for such period as set forth in the KPI Metrics Report is more than or equal to the Transmission Pipeline Inspection KPI Threshold B for such period but less than the Transmission Pipeline Inspection KPI Target B for such period, and (c) negative 0.020%, if the Transmission Pipeline Inspection KPI for such period as set forth in the KPI Metrics Report is more than or equal to Transmission Pipeline Inspection KPI Target B for such period.

"Transmission Pipeline Inspection KPI Facility Fee Adjustment Amount" means, with respect to any period between Sustainability Pricing Adjustment Dates, (a) positive 0.005%, if the Transmission Pipeline Inspection KPI for such period as set forth in the KPI Metrics Report is less than the Transmission Pipeline Inspection KPI Threshold B for such period, (b) 0.000%, if the Transmission Pipeline Inspection KPI for such period as set forth in the KPI Metrics Report is more than or equal to the Transmission Pipeline Inspection KPI Threshold B for such period but less than the Transmission Pipeline Inspection KPI Target B for such period, and (c) negative 0.005%, if the Transmission Pipeline Inspection KPI for such period as set forth in the KPI Metrics Report is more than or equal to Transmission Pipeline Inspection KPI Target B for such period.

"Transmission Pipeline Inspection KPI Target B" means, with respect to any calendar year, the Transmission Pipeline Inspection KPI Target B for such calendar year as set forth in the Sustainability Table.

"Transmission Pipeline Inspection KPI Threshold B" means, with respect to any Reference Year, the Transmission Pipeline Inspection KPI Threshold B for such Reference Year as set forth in the Sustainability Table.

"Type", when used in reference to any Loan or Borrowing, refers to whether the rate of interest on such Loan, or on the Loans comprising such Borrowing, is determined by reference to the Adjusted Term SOFR Rate, Adjusted Daily Simple SOFR or the Alternate Base Rate.

"UK Financial Institutions" means any BRRD Undertaking (as such term is defined under the PRA Rulebook (as amended from time to time) promulgated by the United Kingdom Prudential Regulation Authority) or any person falling within IFPRU 11.6 of the FCA Handbook (as amended from time to time) promulgated by the United Kingdom Financial Conduct Authority, which includes certain credit institutions and investment firms, and certain affiliates of such credit institutions or investment firms.

"UK Resolution Authority" means the Bank of England or any other public administrative authority having responsibility for the resolution of any UK Financial Institution.

"Unadjusted Benchmark Replacement" means the applicable Benchmark Replacement excluding the related Benchmark Replacement Adjustment.

"U.S. Government Securities Business Day" means, any day except for (i) a Saturday, (ii) a Sunday or (iii) a day on which the Securities Industry and Financial Markets Association recommends that the fixed income departments of its members be closed for the entire day for purposes of trading in United States government securities.

"U.S. Person" means a "United States person" within the meaning of Section 7701(a)(30) of the Code.

"U.S. Tax Compliance Certificate" has the meaning assigned to such term in Section 2.17(f)(ii)(B)(3).

"Withdrawal Liability" means liability to a Multiemployer Plan as a result of a complete or partial withdrawal from such Multiemployer Plan, as such terms are defined in Part 1 of Subtitle E of Title IV of ERISA.

"Write-Down and Conversion Powers" means, (a) with respect to any EEA Resolution Authority, the write-down and conversion powers of such EEA Resolution Authority from time to time under the Bail-In Legislation for the applicable EEA Member Country, which write-down and conversion powers are described in the EU Bail-In Legislation Schedule, and (b) with respect to the United Kingdom, any powers of the applicable Resolution Authority under the Bail-In Legislation to cancel, reduce, modify or change the form of a liability of any UK Financial Institution or any contract or instrument under which that liability arises, to convert all or part of that liability into shares, securities or obligations of that person or any other person, to provide that any such contract or instrument is to have effect as if a right had been exercised under it or to suspend any obligation in respect of that liability or any of the powers under that Bail-In Legislation that are related to or ancillary to any of those powers.

SECTION 1.02 Classification of Loans and Borrowings. For purposes of this Agreement, Loans may be classified and referred to by Class (e.g., a "Revolving Loan") or by Type (e.g., a "Term Benchmark Loan" or an "RFR Loan") or by Class and Type (e.g., a "Term Benchmark Revolving Loan"). Borrowings also may be classified and referred to by Class (e.g., a "Revolving Borrowing") or by Type (e.g., a "Term Benchmark Borrowing" or an "RFR Borrowing") or by Class and Type (e.g., a "Term Benchmark Revolving Borrowing").

SECTION 1.03 Terms Generally. The definitions of terms herein shall apply equally to the singular and plural forms of the terms defined. Whenever the context may require, any pronoun shall include the corresponding masculine, feminine and neuter forms. The words "include", "includes" and "including" shall be deemed to be followed by the phrase "without limitation". The word "will" shall be construed to have the same meaning and effect as the word "shall". The word "law" shall be construed as referring to all statutes, rules, regulations, codes and other laws (including official rulings and interpretations thereunder having the force of law or with which affected Persons customarily comply), and all judgments, orders and decrees, of all Governmental Authorities. Unless the context requires otherwise (a) any definition of or reference to any agreement, instrument or other document herein shall be construed as referring to such agreement, instrument or other document as from time to time amended, restated, supplemented or otherwise modified (subject to any restrictions on such amendments, restatements, supplements or modifications set forth herein), (b) any reference herein to any Person shall be construed to include such Person's successors and assigns (subject to any restrictions on assignment set forth herein) and, in the case of any Governmental Authority, any other Governmental Authority that shall have succeeded to any or all functions thereof, (c) the words "herein", "hereof" and "hereunder", and words of similar import, shall be construed to refer to this Agreement in its entirety and not to any particular provision hereof, (d) all references herein to Articles, Sections, Exhibits and Schedules shall be construed to refer to Articles and Sections of, and Exhibits and Schedules to, this Agreement, (e) any reference to any law, rule or regulation herein shall, unless otherwise specified, refer to such law, rule or regulation as amended, modified or supplemented from time to time and (f) the words "asset" and "property" shall be construed to have the same meaning and effect and to refer to any and all tangible and intangible assets and properties, including cash, securities, accounts and contract rights.

SECTION 1.04 Accounting Terms; GAAP; Pro Forma Calculations. (a) Except as otherwise expressly provided herein, all terms of an accounting or financial nature shall be construed in accordance with GAAP, as in effect from time to time; provided that, if the Borrower notifies the Administrative Agent that the Borrower requests an amendment to any provision hereof to eliminate the effect of any change occurring after the date hereof in GAAP or in the application thereof on the operation of such provision (or if the Administrative Agent notifies the Borrower that the Required Lenders request an amendment to any provision hereof for such purpose), regardless of whether any such notice is given before or after such change in GAAP or in the application thereof, then such provision shall be interpreted on the basis of GAAP as in effect and applied immediately before such change shall have become effective until such notice shall have been withdrawn or such provision amended in accordance herewith. Notwithstanding any other provision contained herein, all terms of an accounting or financial nature used herein shall be construed, and all computations of amounts and ratios referred to herein shall be made without giving effect to (i) any election under Financial Accounting Standards Board Accounting Standards Codification 825 (or any other Financial Accounting Standard having a similar result or effect) to value any Indebtedness or other liabilities of the Borrower or any Subsidiary at "fair value", as defined therein and (ii) any treatment of Indebtedness in respect of convertible debt instruments under Accounting Standards Codification 470-20 (or any other Accounting Standards Codification or Financial Accounting Standard having a similar result or effect) to value any such Indebtedness in a reduced or bifurcated manner as described therein, and such Indebtedness shall at all times be valued at the full stated principal amount thereof.

(b) All pro forma computations required to be made hereunder giving effect to any acquisition or disposition, or issuance, incurrence or assumption of Indebtedness, or other transaction shall in each case be calculated giving pro forma effect thereto (and, in the case of any pro forma computation made hereunder to determine whether such acquisition or disposition, or issuance, incurrence or assumption of Indebtedness, or other transaction is permitted to be consummated hereunder, to any other such transaction consummated since the first day of the period covered by any component of such pro forma computation and on or prior to the date of such computation) as if such transaction had occurred on the first day of the period of four consecutive fiscal quarters ending with the most recent fiscal quarter for which financial statements shall have been delivered pursuant to Section 5.01(a) or 5.01(b) (or, prior to the delivery of any such financial statements, ending with the last fiscal quarter included in the financial statements referred to in Section 3.03(a)), and, to the extent applicable, to the historical earnings and cash flows associated with the assets acquired or disposed of (but without giving effect to any synergies or cost savings) and any related incurrence or reduction of Indebtedness, all in accordance with Article 11 of Regulation S-X under the Securities Act. If any Indebtedness bears a floating rate of interest and is being given pro forma effect, the interest on such Indebtedness shall be calculated as if the rate in effect on the date of determination had been the applicable rate for the entire period (taking into account any Swap Agreement applicable to such Indebtedness).

(c) Notwithstanding anything to the contrary contained in Section 1.04(a), any change in accounting for leases pursuant to GAAP resulting from the adoption of Financial Accounting Standards Board Accounting Standards Update No. 2016-02, Leases (Topic 842) ("FAS 842"), to the extent such adoption would require treating any lease (or similar arrangement conveying the right to use) as a capital lease where such lease (or similar arrangement) would not have been required to be so treated under GAAP as in effect on December 31, 2015, such lease shall not be considered a capital lease, and all calculations (including with respect to assets and liabilities associated with such lease) and deliverables under this Agreement or any other Loan Document shall be made or delivered, as applicable, in accordance therewith.

SECTION 1.05 Interest Rates; Benchmark Notification. The interest rate on a Loan denominated in Dollars may be derived from an interest rate benchmark that may be discontinued or is, or may in the future become, the subject of regulatory reform. Upon the occurrence of a Benchmark Transition Event, Section 2.14(b) provides a mechanism for determining an alternative rate of interest. The Administrative Agent does not warrant or accept any responsibility for, and shall not have any liability with respect to, the administration, submission, performance or any other matter related to any interest rate used in this Agreement, or with respect to any alternative or successor rate thereto, or replacement rate thereof, including without limitation, whether the composition or characteristics of any such alternative, successor or replacement reference rate will be similar to, or produce the same value or economic equivalence of, the existing interest rate being replaced or have the same volume or liquidity as did any existing interest rate prior to its discontinuance or unavailability. The Administrative Agent and its affiliates and/or other related entities may engage in transactions that affect the calculation of any interest rate used in this Agreement or any alternative, successor or alternative rate (including any Benchmark Replacement) and/or any relevant adjustments thereto, in each case, in a manner adverse to the Borrower. The Administrative Agent may select information sources or services in its reasonable discretion to ascertain any interest rate used in this Agreement, any component thereof, or rates referenced in the definition thereof, in each case pursuant to the terms of this Agreement, and shall have no liability to the Borrower, any Lender or any other Person or entity for damages of any kind, including direct or indirect, special, punitive, incidental or consequential damages, costs, losses or expenses (whether in tort, contract or otherwise and whether at law or in equity), for any error or calculation of any such rate (or component thereof) provided by any such information source or service.

SECTION 1.06 Divisions. For all purposes under the Loan Documents, in connection with any division or plan of division under Delaware law (or any comparable event under a different jurisdiction's laws): (a) if any asset, right, obligation or liability of any Person becomes the asset, right, obligation or liability of a different Person, then it shall be deemed to have been transferred from the original Person to the subsequent Person, and (b) if any new Person comes into existence, such new Person shall be deemed to have been organized and acquired on the first date of its existence by the holders of its Equity Interests at such time.

SECTION 1.07 Amendment and Restatement.

(a) The parties to this Agreement agree that, on the Restatement Effective Date, the terms and provisions of the Existing Credit Agreement shall be and hereby are amended, superseded and restated in their entirety by the terms and provisions of this Agreement. Neither the execution, delivery and acceptance of this Agreement nor any of the terms, covenants, conditions or other provisions set forth herein are intended, nor shall they be deemed or construed, to effect a novation of any liens or indebtedness or other obligations under the Existing Credit Agreement or any other Loan Document (as defined in the Existing Credit Agreement) or to pay, extinguish, release, satisfy or discharge (i) all or any part of the indebtedness or other obligations evidenced by the Existing Credit Agreement, (ii) the liability of any Person under the Existing Credit Agreement or the Loan Documents (as defined under the Existing Credit Agreement) executed and delivered in connection therewith or (iii) the liability of any Person with respect to the Existing Credit Agreement or any indebtedness or other obligations evidenced thereby. All Loans made, and Obligations incurred, under the Existing Credit Agreement which are outstanding on the Restatement Effective Date (and not terminated or otherwise repaid with the proceeds of any Loans made hereunder on the Restatement Effective Date) shall be re-evidenced as Loans and Obligations, respectively, under (and shall be governed by the terms of) this Agreement and the other Loan Documents.

(b) Without limiting the foregoing, upon the effectiveness of the amendment and restatement contemplated hereby on the Restatement Effective Date and except as otherwise expressly provided herein:

(i) all references in the "Loan Documents" (as defined in the Existing Credit Agreement) to the "Administrative Agent", the "Credit Agreement" and the "Loan Documents" shall be deemed to refer to the Administrative Agent, this Agreement and the Loan Documents;

(ii) the "Commitments" and the "Letter of Credit Commitments" (as defined in the Existing Credit Agreement) shall continue as Commitments and Letter of Credit Commitments, respectively, hereunder as set forth on the applicable Commitment Schedule;

(iii) the "Loans" (as defined in the Existing Credit Agreement) outstanding under the Existing Credit Agreement, if any, shall continue as Loans hereunder;

(iv) the Administrative Agent shall make such reallocations, sales, assignments or other relevant actions in respect of the applicable "Commitments" and "Revolving Credit Exposure" (each as defined in and in effect under the Existing Credit Agreement) as are necessary in order that each Lender's Revolving Credit Exposure hereunder reflects such Lender's Applicable Percentage thereof on the Restatement Effective Date (and in no event exceeds each such Lender's Commitment hereunder), and the Borrower and each Lender that was a "Lender" under the Existing Credit Agreement (constituting the "Required Lenders" under and as defined therein) hereby agrees (with effect immediately prior to the Restatement Effective Date) that (x) such reallocation, sales and assignments shall be deemed to have been effected by way of, and subject to the terms and conditions of, Assignment and Assumptions, without the payment of any related assignment fee, and no other documents or instruments shall be, or shall be required to be, executed in connection with such assignments (all of which are hereby waived), (y) such reallocation shall satisfy the assignment provisions of Section 9.04 of the Existing Credit Agreement and (z) in connection with such reallocation, sales, assignments or other relevant actions, the Borrower shall pay all interest and fees outstanding under the Existing Credit Agreement and accrued to the date hereof to the Administrative Agent for the account of the Lenders party hereto, together with any losses, costs and expenses incurred by Lenders under Section 2.16 of the Existing Credit Agreement; and

(v) each of the signatories hereto that is also a party to the Existing Credit Agreement hereby consents to any of the actions described in the foregoing clause (iv) and agrees that any and all required notices and required notice periods under the Existing Credit Agreement in connection with any of the actions described in the foregoing clause (iv) on the Restatement Effective Date are hereby waived and of no force and effect.

SECTION 1.08 Sustainability Adjustments.

(a) Following the date on which the Borrower provides a Pricing Certificate in respect of any Reference Year, (i) the per annum rates set forth under the captions "Term Benchmark Spread" (including with respect to the Letter of Credit fees payable pursuant to Section 2.12(b)(i)) and "ABR Spread" in the definition of Applicable Rate shall be increased or decreased (or neither increased nor decreased), as applicable, pursuant to the Sustainability Rate Adjustment as set forth in such Pricing Certificate, and (ii) the per annum rates set forth under the caption "Facility Fee Rate" in the definition of Applicable Rate shall be increased or decreased (or neither increased nor decreased), as applicable, pursuant to the Sustainability Facility Fee Adjustment as set forth in such Pricing Certificate. For purposes of the foregoing, (A) the Sustainability Rate Adjustment and the Sustainability Facility Fee Adjustment shall be determined as of the fifth Business Day following receipt by the Administrative Agent of a Pricing Certificate delivered pursuant to Section 1.08(f) based upon the KPI Metrics set forth in such Pricing Certificate and the calculations of the Sustainability Rate Adjustment and the Sustainability Facility Fee Adjustment, therein (such day, the "Sustainability Pricing Adjustment Date") and (B) each change in the Applicable Rate resulting from a Pricing Certificate shall be effective during the period commencing on and including the applicable Sustainability Pricing Adjustment Date and ending on the date immediately preceding the next such Sustainability Pricing Adjustment Date (or, in the case of non-delivery of a Pricing Certificate, the last day such Pricing Certificate could have been delivered pursuant to the terms of Section 1.08(f)).

(b) For the avoidance of doubt, only one Pricing Certificate may be delivered in respect of any Reference Year. It is further understood and agreed that the per annum rates set forth under the captions "Term Benchmark Spread" (including with respect to the Letter of Credit fees payable pursuant to Section 2.12(b)(i)) and "ABR Spread" in the definition of Applicable Rate will never be reduced or increased by more than 0.040% and that the per annum rates set forth under the caption "Facility Fee Rate" in the definition of Applicable Rate will never be reduced or increased by more than 0.010%, pursuant to the Sustainability Rate Adjustment and the Sustainability Facility Fee Adjustment, respectively, during any Reference Year. For the avoidance of doubt, any adjustment to the Applicable Rate shall not be cumulative year-over-year. Each applicable adjustment shall only apply until the date on which the next adjustment is due to take place. Notwithstanding anything to the contrary in this Agreement, the Sustainability Rate Adjustment and the Sustainability Fee Adjustment shall be 0.000% at all times from and after June 30, 2027.

(c) It is hereby understood and agreed that if no such Pricing Certificate is delivered by the Borrower with regard to a particular Reference Year within the period set forth in Section 1.08(f), the Sustainability Rate Adjustment will be positive 0.040% and the Sustainability Facility Fee Adjustment will be positive 0.010% commencing on the last day such Pricing Certificate could have been delivered pursuant to the terms of Section 1.08(f) and continuing until the Borrower delivers Pricing Certificate to the Administrative Agent for the applicable Reference Year.

(d) If (i)(A) the Borrower or any Lender becomes aware of any material inaccuracy in the Sustainability Rate Adjustment, the Sustainability Facility Fee Adjustment or the KPI Metrics as reported in a Pricing Certificate (any such material inaccuracy, a "Pricing Certificate Inaccuracy") and, in the case of any Lender, such Lender delivers, not later than 10 Business Days after obtaining knowledge thereof, a written notice to the Administrative Agent describing such Pricing Certificate Inaccuracy in reasonable detail (which description shall be shared with each Lender and the Borrower), or (B) the Borrower and the Administrative Agent shall mutually agree that there was a Pricing Certificate Inaccuracy at the time of delivery of a Pricing Certificate, and (ii) a proper calculation of the Sustainability Rate Adjustment, Sustainability Facility Fee Adjustment or the KPI Metrics would have resulted in an increase in the Applicable Rate for any period, the Borrower shall be obligated to pay to the Administrative Agent for the account of the applicable Lenders or the applicable L/C Issuers, as the case may be, promptly on demand by the Administrative Agent (or, after the occurrence of an actual or deemed entry of an order for relief with respect to any Borrower under the Bankruptcy Code (or any comparable event under non-U.S. Debtor Relief Laws), automatically and without further action by the Administrative Agent, any Lender or any L/C Issuer), but in any event within 10 Business Days after the Borrower has received written notice of, or has agreed in writing that there was, a Pricing Certificate Inaccuracy, an amount equal to the excess of (1) the amount of interest and fees that should have been paid for such period over (2) the amount of interest and fees actually paid for such period.

(e) It is understood and agreed that any Pricing Certificate Inaccuracy shall not constitute a Default or Event of Default; provided, that, the Borrower complies with the terms of the immediately preceding paragraph with respect to such Pricing Certificate Inaccuracy. Notwithstanding anything to the contrary herein, unless such amounts shall be due upon the occurrence of an actual or deemed entry of an order for relief with respect to a Borrower under the Bankruptcy Code (or any comparable event under non-U.S. Debtor Relief Laws), (a) any additional amounts required to be paid pursuant to the immediately preceding paragraph shall not be due and payable until the earlier to occur of (i) a written demand is made for such payment by the Administrative Agent in accordance with such paragraph or (ii) 10 Business Days after the Borrower has received written notice of, or has agreed in writing that there was, a Pricing Certificate Inaccuracy (such date, the "Certificate Inaccuracy Payment Date"), (b) any nonpayment of such additional amounts prior to the Certificate Inaccuracy Payment Date shall not constitute a Default (whether retroactively or otherwise) and (c) none of such additional amounts shall be deemed overdue prior to the Certificate Inaccuracy Payment Date or shall accrue interest at the Default Rate prior to the Certificate Inaccuracy Payment Date.

(f) Each party hereto hereby agrees that neither the Sustainability Structuring Agent nor the Administrative Agent shall have any responsibility for (or liability in respect of) reviewing, auditing or otherwise evaluating any calculation by the Borrower of any Sustainability Rate Adjustment or Sustainability Facility Fee Adjustment (or any of the data or computations that are part of or related to any such calculation) set forth in any Pricing Certificate (and the Administrative Agent and the Lenders may rely conclusively on any such certificate, without further inquiry).

(g) As soon as available and in any event within 180 days following the end of each fiscal year of the Borrower (commencing with the fiscal year ending December 31, 2021), the Borrower shall deliver to the Administrative Agent and the Lenders, in form and detail satisfactory to the Administrative Agent and the Required Lenders: a Pricing Certificate for the most recently-ended Reference Year; provided, that, for any Reference Year the Borrower may elect not to deliver a Pricing Certificate, and such election shall not constitute a Default or Event of Default (but such failure to so deliver a Pricing Certificate by the end of such 180-day period shall result in the Sustainability Rate Adjustment being applied as set forth in Section 1.08(c).

SECTION 1.09 Letter of Credit Amounts. Unless otherwise specified herein, the amount of a Letter of Credit at any time shall be deemed to be the amount of such Letter of Credit available to be drawn at such time; provided that with respect to any Letter of Credit that, by its terms or the terms of any Letter of Credit Agreement related thereto, provides for one or more automatic increases in the available amount thereof, the amount of such Letter of Credit shall be deemed to be the maximum amount of such Letter of Credit after giving effect to all such increases, whether or not such maximum amount is available to be drawn at such time.

ARTICLE II

The Credits

SECTION 2.01 Commitments. Subject to the terms and conditions set forth herein, each Lender (severally and not jointly) agrees to make Revolving Loans to the Borrower in Dollars from time to time during the Availability Period in an aggregate principal amount that will not result (after giving effect to any application of proceeds of such Borrowing pursuant to Section 2.10) in (a) such Lender's Revolving Credit Exposure exceeding such Lender's Commitment or (b) the Total Revolving Credit Exposure exceeding the Aggregate Commitment. Within the foregoing limits and subject to the terms and conditions set forth herein, the Borrower may borrow, prepay and reborrow Revolving Loans.

SECTION 2.02 Loans and Borrowings. (a) Each Revolving Loan shall be made as part of a Borrowing consisting of Revolving Loans made by the Lenders ratably in accordance with their respective Commitments. The failure of any Lender to make any Loan required to be made by it shall not relieve any other Lender of its obligations hereunder; provided that the Commitments of the Lenders are several and no Lender shall be responsible for any other Lender's failure to make Loans as required. Any Swingline Loan shall be made in accordance with the procedures set forth in Section 2.05.

(b) Subject to Section 2.14, each Revolving Borrowing shall be comprised entirely of ABR Loans, Term Benchmark Loans or RFR Loans as the Borrower may request in accordance herewith. Each Swingline Loan shall be an ABR Loan. Each Lender at its option may make any Term Benchmark Loan by causing any domestic or foreign branch or Affiliate of such Lender to make such Loan (and in the case of an Affiliate, the provisions of Sections 2.14, 2.15, 2.16 and 2.17 shall apply to such Affiliate to the same extent as to such Lender); provided that any exercise of such option shall not affect the obligation of the Borrower to repay such Loan in accordance with the terms of this Agreement.

(c) At the commencement of each Interest Period for any Term Benchmark Revolving Borrowing, such Borrowing shall be in an aggregate amount that is an integral multiple of $1,000,000 thereof. At the time that each ABR Revolving Borrowing and/or RFR Borrowing is made, such Borrowing shall be in an aggregate amount that is an integral multiple of $1,000,000; provided that an ABR Revolving Borrowing may be in an aggregate amount that is equal to the entire unused balance of the Aggregate Commitment or that is required to finance the reimbursement of an LC Disbursement as contemplated by Section 2.06(e). Each Swingline Loan shall be in an amount that is an integral multiple of $1,000,000. Borrowings of more than one Type and Class may be outstanding at the same time; provided that there shall not at any time be more than a total of eight (8) Term Benchmark Borrowings or RFR Borrowings outstanding.

(d) Notwithstanding any other provision of this Agreement, the Borrower shall not be entitled to request, or to elect to convert or continue, any Borrowing if the Interest Period requested with respect thereto would end after the Maturity Date.

SECTION 2.03 Requests for Revolving Borrowings. To request a Revolving Borrowing, the Borrower shall notify the Administrative Agent of such request by submitting a Borrowing Request (a)(i) in the case of a Term Benchmark Borrowing, not later than 11:00 a.m., New York City time, three (3) U.S. Government Securities Business Days before the date of the proposed Borrowing or (ii) in the case of an RFR Borrowing, not later than 11:00 a.m., New York City time, five (5) U.S. Government Securities Business Days before the date of the proposed Borrowing or (b) in the case of an ABR Borrowing, not later than 1:00 p.m., New York City time, on the date of the proposed Borrowing; provided that any such notice of an ABR Revolving Borrowing to finance the reimbursement of an LC Disbursement as contemplated by Section 2.06(e) may be given not later than 10:00 a.m., New York City time, on the date of the proposed Borrowing. Each such Borrowing Request shall be irrevocable and shall be signed by an Authorized Officer of the Borrower. Each such Borrowing Request shall specify the following information in compliance with Section 2.02:

(i) the aggregate principal amount of the requested Borrowing;

(ii) the date of such Borrowing, which shall be a Business Day;

(iii) whether such Borrowing is to be an ABR Borrowing, a Term Benchmark Borrowing or an RFR Borrowing;

(iv) in the case of a Term Benchmark Borrowing, the initial Interest Period to be applicable thereto, which shall be a period contemplated by the definition of the term "Interest Period"; and

(v) the location and number of the Borrower's account to which funds are to be disbursed, which shall comply with the requirements of Section 2.07.

If no election as to the Type of Revolving Borrowing is specified, then the requested Revolving Borrowing shall be an ABR Borrowing. If no Interest Period is specified with respect to any requested Term Benchmark Revolving Borrowing, then the Borrower shall be deemed to have selected an Interest Period of one month's duration. Promptly following receipt of a Borrowing Request in accordance with this Section, the Administrative Agent shall advise each Lender of the details thereof and of the amount of such Lender's Loan to be made as part of the requested Borrowing. Notwithstanding the foregoing, in no event shall the Borrower be permitted to request pursuant to this Section 2.03 an RFR Loan bearing interest based on Daily Simple SOFR prior to a Benchmark Transition Event and Benchmark Replacement Date with respect to the Term SOFR Rate (it being understood and agreed that Daily Simple SOFR shall only apply to the extent provided in Sections 2.14(a) and 2.14(f).

SECTION 2.04 Intentionally Omitted.

SECTION 2.05 Swingline Loans. (a) Subject to the terms and conditions set forth herein, from time to time during the Availability Period the Swingline Lender shall make Swingline Loans in Dollars to the Borrower in an aggregate principal amount at any time outstanding that will not result in (i) the aggregate principal amount of outstanding Swingline Loans exceeding $15,000,000, (ii) the Swingline Lender's Revolving Credit Exposure exceeding its Commitment, or (iii) the Total Revolving Credit Exposure exceeding the Aggregate Commitment; provided that the Swingline Lender shall not be required to make a Swingline Loan to refinance an outstanding Swingline Loan. Within the foregoing limits and subject to the terms and conditions set forth herein, the Borrower may borrow, prepay and reborrow Swingline Loans; provided that Swingline Loans may not be outstanding for more than 10 Business Days in any calendar month.

(b) To request a Swingline Loan, the Borrower shall submit a written notice to the Administrative Agent by telecopy or electronic mail not later than 1:00 p.m., New York City time, on the day of a proposed Swingline Loan. Each such notice shall be in a form approved by the Administrative Agent, shall be irrevocable and shall specify the requested date (which shall be a Business Day) and amount of the requested Swingline Loan. The Administrative Agent will promptly advise the Swingline Lender of any such notice received from the Borrower. The Swingline Lender shall make each Swingline Loan available to the Borrower by means of a wire transfer of immediately available funds to an account designated by the Borrower (or, in the case of a Swingline Loan made to finance the reimbursement of an LC Disbursement as provided in Section 2.06(e), by remittance to the Issuing Bank) by 3:00 p.m., New York City time, on the requested date of such Swingline Loan.

(c) The Swingline Lender may by written notice given to the Administrative Agent require the Lenders to acquire participations in all or a portion of the Swingline Loans outstanding. Such notice shall specify the aggregate amount of Swingline Loans in which Lenders will participate. Promptly upon receipt of such notice, the Administrative Agent will give notice thereof to each Lender, specifying in such notice such Lender's Applicable Percentage of such Swingline Loan or Loans. Each Lender hereby absolutely and unconditionally agrees, promptly upon receipt of such notice from the Administrative Agent (and in any event, if such notice is received by 12:00 noon, New York City time, on a Business Day, no later than 5:00 p.m. New York City time on such Business Day and if received after 12:00 noon, New York City time, on a Business Day, no later than 10:00 a.m. New York City time on the immediately succeeding Business Day) to pay to the Administrative Agent, for the account of the Swingline Lender, such Lender's Applicable Percentage of such Swingline Loan or Loans. Each Lender acknowledges and agrees that its obligation to acquire participations in Swingline Loans pursuant to this paragraph is absolute and unconditional and shall not be affected by any circumstance whatsoever, including the occurrence and continuance of a Default or reduction or termination of the Commitments, and that each such payment shall be made without any offset, abatement, withholding or reduction whatsoever. Each Lender shall comply with its obligation under this paragraph by wire transfer of immediately available funds, in the same manner as provided in Section 2.07 with respect to Loans made by such Lender (and Section 2.07 shall apply, mutatis mutandis, to the payment obligations of the Lenders), and the Administrative Agent shall promptly pay to the Swingline Lender the amounts so received by it from the Lenders. The Administrative Agent shall notify the Borrower of any participations in any Swingline Loan acquired pursuant to this paragraph, and thereafter payments in respect of such Swingline Loan shall be made to the Administrative Agent and not to the Swingline Lender. Any amounts received by the Swingline Lender from the Borrower (or other party on behalf of the Borrower) in respect of a Swingline Loan after receipt by the Swingline Lender of the proceeds of a sale of participations therein shall be promptly remitted to the Administrative Agent; any such amounts received by the Administrative Agent shall be promptly remitted by the Administrative Agent to the Lenders that shall have made their payments pursuant to this paragraph and to the Swingline Lender, as their interests may appear; provided that any such payment so remitted shall be repaid to the Swingline Lender or to the Administrative Agent, as applicable, if and to the extent such payment is required to be refunded to the Borrower for any reason. The purchase of participations in a Swingline Loan pursuant to this paragraph shall not relieve the Borrower of any default in the payment thereof.

(d) The Swingline Lender may be replaced at any time by written agreement among the Borrower, the Administrative Agent, the replaced Swingline Lender and the successor Swingline Lender. The Administrative Agent shall notify the Lenders of any such replacement of the Swingline Lender. At the time any such replacement shall become effective, the Borrower shall pay all unpaid interest accrued for the account of the replaced Swingline Lender pursuant to Section 2.13(a). From and after the effective date of any such replacement, (x) the successor Swingline Lender shall have all the rights and obligations of the replaced Swingline Lender under this Agreement with respect to Swingline Loans made thereafter and (y) references herein to the term "Swingline Lender" shall be deemed to refer to such successor or to any previous Swingline Lender, or to such successor and all previous Swingline Lenders, as the context shall require. After the replacement of the Swingline Lender hereunder, the replaced Swingline Lender shall remain a party hereto and shall continue to have all the rights and obligations of a Swingline Lender under this Agreement with respect to Swingline Loans made by it prior to its replacement, but shall not be required to make additional Swingline Loans.

(e) Subject to the appointment and acceptance of a successor Swingline Lender, the Swingline Lender may resign as Swingline Lender at any time upon thirty days' prior written notice to the Administrative Agent, the Borrower and the Lenders, in which case, the Swingline Lender shall be replaced in accordance with Section 2.05(d) above.

SECTION 2.06 Letters of Credit. (a) General. Subject to the terms and conditions set forth herein, the Borrower may request the issuance of Letters of Credit denominated in Dollars as the applicant thereof for the support of its or its Subsidiaries' obligations, in a form reasonably acceptable to the Administrative Agent and the applicable Issuing Bank, at any time and from time to time during the Availability Period. In the event of any inconsistency between the terms and conditions of this Agreement and the terms and conditions of any Letter of Credit Agreement, the terms and conditions of this Agreement shall control. Notwithstanding anything herein to the contrary, no Issuing Bank shall have any obligation hereunder to issue, and shall not issue, any Letter of Credit the proceeds of which would be made available to any Person (i) to fund any activity or business of or with any Sanctioned Person, or in any country or territory that, at the time of such funding, is the subject of any Sanctions, (ii) in any manner that would result in a violation of any Sanctions by any party to this Agreement or (iii) in any manner that would result in a violation of one or more policies of such Issuing Bank applicable to letters of credit generally.

(b) Notice of Issuance, Amendment, Renewal, Extension; Certain Conditions. To request the issuance of a Letter of Credit (or the amendment, renewal or extension of an outstanding Letter of Credit), the Borrower shall hand deliver or telecopy (or transmit by electronic communication, if arrangements for doing so have been approved by the applicable Issuing Bank) to the applicable Issuing Bank and the Administrative Agent (reasonably in advance of the requested date of issuance, amendment, renewal or extension, but in any event no less than three (3) Business Days) a notice requesting the issuance of a Letter of Credit, or identifying the Letter of Credit to be amended, renewed or extended, and specifying the date of issuance, amendment, renewal or extension (which shall be a Business Day), the date on which such Letter of Credit is to expire (which shall comply with paragraph (c) of this Section), the amount of such Letter of Credit, the name and address of the beneficiary thereof and such other information as shall be necessary to prepare, amend, renew or extend such Letter of Credit. In addition, as a condition to any such Letter of Credit issuance, the Borrower shall have entered into a continuing agreement (or other letter of credit agreement) for the issuance of letters of credit and/or shall submit a letter of credit application, in each case, as required by the applicable Issuing Bank and using such Issuing Bank's standard form (each, a "Letter of Credit Agreement"). A Letter of Credit shall be issued, amended, renewed or extended only if (and upon issuance, amendment, renewal or extension of each Letter of Credit the Borrower shall be deemed to represent and warrant that), after giving effect to such issuance, amendment, renewal or extension (i) (x) the aggregate undrawn amount of all outstanding Letters of Credit issued by any Issuing Bank at such time plus (y) the aggregate amount of all LC Disbursements made by such Issuing Bank that have not yet been reimbursed by or on behalf of the Borrower at such time shall not exceed such Issuing Bank's Letter of Credit Commitment, (ii) the LC Exposure shall not exceed $60,000,000, (iii) no Lender's Revolving Credit Exposure shall exceed its Commitment, and (iv) the Total Revolving Credit Exposure shall not exceed the Aggregate Commitment. The Borrower may, at any time and from time to time, reduce the Letter of Credit Commitment of any Issuing Bank with the consent of such Issuing Bank; provided that the Borrower shall not reduce the Letter of Credit Commitment of any Issuing Bank if, after giving effect of such reduction, the conditions set forth in clauses (i) through (iv) above shall not be satisfied.

An Issuing Bank shall not be under any obligation to issue any Letter of Credit if:

(i) any order, judgment or decree of any Governmental Authority or arbitrator shall by its terms purport to enjoin or restrain such Issuing Bank from issuing such Letter of Credit, or any law applicable to such Issuing Bank shall prohibit, or require that such Issuing Bank refrain from, the issuance of letters of credit generally or such Letter of Credit in particular or shall impose upon such Issuing Bank with respect to such Letter of Credit any restriction, reserve or capital or liquidity requirement (for which such Issuing Bank is not otherwise compensated hereunder) not in effect on the Restatement Effective Date, or shall impose upon such Issuing Bank any unreimbursed loss, cost or expense that was not applicable on the Restatement Effective Date and that such Issuing Bank in good faith deems material to it; or

(ii) the issuance of such Letter of Credit would violate one or more policies of such Issuing Bank applicable to letters of credit generally.

(c) Expiration Date. Each Letter of Credit shall expire (or be subject to termination by notice from the applicable Issuing Bank to the beneficiary thereof) at or prior to the close of business on the earlier of (i) the date one year after the date of the issuance of such Letter of Credit (or, in the case of any renewal or extension thereof, one year after such renewal or extension) and (ii) the date that is five (5) Business Days prior to the Maturity Date.

(d) Participations. By the issuance of a Letter of Credit (or an amendment to a Letter of Credit increasing the amount thereof) and without any further action on the part of the applicable Issuing Bank or the Lenders, such Issuing Bank hereby grants to each Lender, and each Lender hereby acquires from such Issuing Bank, a participation in such Letter of Credit equal to such Lender's Applicable Percentage of the aggregate amount available to be drawn under such Letter of Credit. In consideration and in furtherance of the foregoing, each Lender hereby absolutely and unconditionally agrees to pay to the Administrative Agent, for the account of such Issuing Bank, such Lender's Applicable Percentage of each LC Disbursement made by such Issuing Bank and not reimbursed by the Borrower on the date due as provided in paragraph (e) of this Section, or of any reimbursement payment required to be refunded to the Borrower for any reason. Each Lender acknowledges and agrees that its obligation to acquire participations pursuant to this paragraph in respect of Letters of Credit is absolute and unconditional and shall not be affected by any circumstance whatsoever, including any amendment, renewal or extension of any Letter of Credit or the occurrence and continuance of a Default or reduction or termination of the Commitments, and that each such payment shall be made without any offset, abatement, withholding or reduction whatsoever.

(e) Reimbursement. If any Issuing Bank shall make any LC Disbursement in respect of a Letter of Credit issued by such Issuing Bank, the Borrower shall reimburse such LC Disbursement by paying to the Administrative Agent in Dollars the amount equal to such LC Disbursement, calculated as of the date such Issuing Bank made such LC Disbursement not later than 12:00 noon, New York City time, on the date that such LC Disbursement is made, if the Borrower shall have received notice of such LC Disbursement prior to 10:00 a.m., New York City time, on such date, or, if such notice has not been received by the Borrower prior to such time on such date, then not later than 12:00 noon, New York City time, on the Business Day immediately following the day that the Borrower receives such notice, if such notice is not received prior to such time on the day of receipt; provided that the Borrower may, subject to the conditions to borrowing set forth herein, request in accordance with Section 2.03 or 2.05 that such payment be financed with an ABR Revolving Borrowing or Swingline Loan in an equivalent amount of such LC Disbursement and, to the extent so financed, the Borrower's obligation to make such payment shall be discharged and replaced by the resulting ABR Revolving Borrowing or Swingline Loan. If the Borrower fails to make such payment when due, the Administrative Agent shall notify each Lender of the applicable LC Disbursement, the payment then due from the Borrower in respect thereof and such Lender's Applicable Percentage thereof. Promptly following receipt of such notice, each Lender shall pay to the Administrative Agent its Applicable Percentage of the payment then due from the Borrower, in the same manner as provided in Section 2.07 with respect to Loans made by such Lender (and Section 2.07 shall apply, mutatis mutandis, to the payment obligations of the Lenders), and the Administrative Agent shall promptly pay to such Issuing Bank the amounts so received by it from the Lenders. Promptly following receipt by the Administrative Agent of any payment from the Borrower pursuant to this paragraph, the Administrative Agent shall distribute such payment to such Issuing Bank or, to the extent that Lenders have made payments pursuant to this paragraph to reimburse such Issuing Bank, then to such Lenders and such Issuing Bank as their interests may appear. Any payment made by a Lender pursuant to this paragraph to reimburse such Issuing Bank for any LC Disbursement (other than the funding of an ABR Revolving Loan or a Swingline Loan as contemplated above) shall not constitute a Loan and shall not relieve the Borrower of its obligation to reimburse such LC Disbursement.

(f) Obligations Absolute. The Borrower's obligation to reimburse LC Disbursements as provided in paragraph (e) of this Section shall be absolute, unconditional and irrevocable, and shall be performed strictly in accordance with the terms of this Agreement under any and all circumstances whatsoever and irrespective of (i) any lack of validity or enforceability of any Letter of Credit, any Letter of Credit Agreement or this Agreement, or any term or provision therein, (ii) any draft or other document presented under a Letter of Credit proving to be forged, fraudulent or invalid in any respect or any statement therein being untrue or inaccurate in any respect, (iii) payment by any Issuing Bank under a Letter of Credit against presentation of a draft or other document that does not comply with the terms of such Letter of Credit, or (iv) any other event or circumstance whatsoever, whether or not similar to any of the foregoing, that might, but for the provisions of this Section, constitute a legal or equitable discharge of, or provide a right of setoff against, the Borrower's obligations hereunder. Neither the Administrative Agent, the Lenders nor the Issuing Banks, nor any of their Related Parties, shall have any liability or responsibility by reason of or in connection with the issuance or transfer of any Letter of Credit or any payment or failure to make any payment thereunder (irrespective of any of the circumstances referred to in the preceding sentence), or any error, omission, interruption, loss or delay in transmission or delivery of any draft, notice or other communication under or relating to any Letter of Credit (including any document required to make a drawing thereunder), any error in interpretation of technical terms or any consequence arising from causes beyond the control of the applicable Issuing Bank; provided that the foregoing shall not be construed to excuse such Issuing Bank from liability to the Borrower to the extent of any direct damages (as opposed to special, indirect, consequential or punitive damages, claims in respect of which are hereby waived by the Borrower to the extent permitted by applicable law) suffered by the Borrower that are caused by such Issuing Bank's failure to exercise care when determining whether drafts and other documents presented under a Letter of Credit comply with the terms thereof. The parties hereto expressly agree that, in the absence of gross negligence or willful misconduct on the part of an Issuing Bank (as finally determined by a non-appealable judgment of court of competent jurisdiction), such Issuing Bank shall be deemed to have exercised care in each such determination. In furtherance of the foregoing and without limiting the generality thereof, the parties agree that, with respect to documents presented which appear on their face to be in substantial compliance with the terms of a Letter of Credit, the applicable Issuing Bank may, in its sole discretion, either accept and make payment upon such documents without responsibility for further investigation, regardless of any notice or information to the contrary, or refuse to accept and make payment upon such documents if such documents are not in strict compliance with the terms of such Letter of Credit.

(g) Disbursement Procedures. The applicable Issuing Bank shall, promptly following its receipt thereof, examine all documents purporting to represent a demand for payment under a Letter of Credit. Such Issuing Bank shall promptly notify the Administrative Agent and the Borrower by telephone (confirmed by telecopy or electronic mail) of such demand for payment and whether such Issuing Bank has made or will make an LC Disbursement thereunder; provided that any failure to give or delay in giving such notice shall not relieve the Borrower of its obligation to reimburse such Issuing Bank and the Lenders with respect to any such LC Disbursement.

(h) Interim Interest. If such Issuing Bank shall make any LC Disbursement, then, unless the Borrower shall reimburse such LC Disbursement in full on the date such LC Disbursement is made, the unpaid amount thereof shall bear interest, for each day from and including the date such LC Disbursement is made to but excluding the date that the reimbursement is due and payable, at the rate per annum then applicable to ABR Revolving Loans and such interest shall be due and payable on the date when such reimbursement is payable; provided that, if the Borrower fails to reimburse such LC Disbursement when due pursuant to paragraph (e) of this Section, then Section 2.13(d) shall apply. Interest accrued pursuant to this paragraph shall be for the account of such Issuing Bank, except that interest accrued on and after the date of payment by any Lender pursuant to paragraph (e) of this Section to reimburse such Issuing Bank shall be for the account of such Lender to the extent of such payment.

(i) Replacement and Resignation of Issuing Bank.

(i) Any Issuing Bank may be replaced at any time by written agreement among the Borrower, the Administrative Agent, the replaced Issuing Bank and the successor Issuing Bank. The Administrative Agent shall notify the Lenders of any such replacement of an Issuing Bank. At the time any such replacement shall become effective, the Borrower shall pay all unpaid fees accrued for the account of the replaced Issuing Bank pursuant to Section 2.12(b). From and after the effective date of any such replacement, (i) the successor Issuing Bank shall have all the rights and obligations of the replaced Issuing Bank under this Agreement with respect to Letters of Credit to be issued thereafter and (ii) references herein to the term "Issuing Bank" shall be deemed to refer to such successor or to any previous Issuing Bank, or to such successor and all previous Issuing Banks, as the context shall require. After the replacement of an Issuing Bank hereunder, the replaced Issuing Bank shall remain a party hereto and shall continue to have all the rights and obligations of an Issuing Bank under this Agreement with respect to Letters of Credit then outstanding and issued by it prior to such replacement, but shall not be required to issue additional Letters of Credit or extend or otherwise amend any existing Letter of Credit.

(ii) Subject to the appointment and acceptance of a successor Issuing Bank, any Issuing Bank may resign as an Issuing Bank at any time upon thirty days' prior written notice to the Administrative Agent, the Borrower and the Lenders, in which case, such resigning Issuing Bank shall be replaced in accordance with Section 2.06(i)(i) above.

(j) Cash Collateralization. If any Event of Default shall occur and be continuing, on the Business Day that the Borrower receives notice from the Administrative Agent or the Required Lenders (or, if the maturity of the Loans has been accelerated, Lenders with LC Exposure representing greater than 50% of the total LC Exposure) demanding the deposit of cash collateral pursuant to this paragraph, the Borrower shall deposit in an account with the Administrative Agent, in the name of the Administrative Agent and for the benefit of the Lenders (the "LC Collateral Account"), an amount in cash equal to 100% of the amount of the LC Exposure as of such date plus any accrued and unpaid interest thereon; provided that the obligation to deposit such cash collateral shall become effective immediately, and such deposit shall become immediately due and payable, without demand or other notice of any kind, upon the occurrence of any Event of Default with respect to the Borrower described in Section 7.01(h) or (i). Such deposit shall be held by the Administrative Agent as collateral for the payment and performance of the Obligations. The Administrative Agent shall have exclusive dominion and control, including the exclusive right of withdrawal, over such account and the Borrower hereby grants to the Administrative Agent a security interest in the LC Collateral Account. Other than any interest earned on the investment of such deposits, which investments shall be made at the option and sole discretion of the Administrative Agent and at the Borrower's risk and expense, such deposits shall not bear interest. Interest or profits, if any, on such investments shall accumulate in such account. Moneys in such account shall be applied by the Administrative Agent to reimburse any applicable Issuing Bank for LC Disbursements for which it has not been reimbursed and, to the extent not so applied, shall be held for the satisfaction of the reimbursement obligations of the Borrower for the LC Exposure at such time or, if the maturity of the Loans has been accelerated (but subject to the consent of Lenders with LC Exposure representing greater than 50% of the total LC Exposure), be applied to satisfy other Obligations. If the Borrower is required to provide an amount of cash collateral hereunder as a result of the occurrence of an Event of Default, such amount (to the extent not applied as aforesaid) shall be returned to the Borrower within three (3) Business Days after all Events of Default have been cured or waived.

(k) Letters of Credit Issued for Account of Subsidiaries. Notwithstanding that a Letter of Credit issued or outstanding hereunder supports any obligations of, or is for the account of, a Subsidiary, or states that a Subsidiary is the "account party," "applicant," "customer," "instructing party," or the like of or for such Letter of Credit, and without derogating from any rights of the applicable Issuing Bank (whether arising by contract, at law, in equity or otherwise) against such Subsidiary in respect of such Letter of Credit, the Borrower (i) shall reimburse, indemnify and compensate the applicable Issuing Bank hereunder for such Letter of Credit (including to reimburse any and all drawings thereunder) as if such Letter of Credit had been issued solely for the account of the Borrower and (ii) irrevocably waives any and all defenses that might otherwise be available to it as a guarantor or surety of any or all of the obligations of such Subsidiary in respect of such Letter of Credit. The Borrower hereby acknowledges that the issuance of such Letters of Credit for its Subsidiaries inures to the benefit of the Borrower, and that the Borrower's business derives substantial benefits from the businesses of such Subsidiaries.

(l) Issuing Bank Agreements. Unless otherwise requested by the Administrative Agent, each Issuing Bank shall report in writing to the Administrative Agent (i) promptly following the end of each calendar month, the aggregate amount of Letters of Credit issued by it and outstanding at the end of such month, (ii) on or prior to each Business Day on which such Issuing Bank expects to issue, amend, renew or extend any Letter of Credit, the date of such issuance, amendment, renewal or extension, and the aggregate face amount of the Letter of Credit to be issued, amended, renewed or extended by it and outstanding after giving effect to such issuance, amendment, renewal or extension occurred (and whether the amount thereof changed), it being understood that such Issuing Bank shall not permit any issuance, renewal, extension or amendment resulting in an increase in the amount of any Letter of Credit to occur without first obtaining written confirmation from the Administrative Agent that it is then permitted under this Agreement, (iii) on each Business Day on which such Issuing Bank makes any payment under any Letter of Credit, the date of such payment under such Letter of Credit and the amount of such payment, (iv) on any Business Day on which the Borrower fails to reimburse any payment under any Letter of Credit required to be reimbursed to such Issuing Bank on such day, the date of such failure and the amount of such payment and (v) on any other Business Day, such other information as the Administrative Agent shall reasonably request.

SECTION 2.07 Funding of Borrowings. (a) Each Lender shall make each Loan to be made by it hereunder on the proposed date thereof solely by wire transfer of immediately available funds by 12:00 noon, New York City time (or, with respect to any ABR Borrowing, the Borrowing Request for which shall have been received after 10:00 a.m. but at or before 1:00 p.m., New York City time, by 3:00 p.m., New York City time), to the account of the Administrative Agent most recently designated by it for such purpose by notice to the Lenders; provided that Swingline Loans shall be made as provided in Section 2.05. Except in respect of the provisions of this Agreement covering the reimbursement of Letters of Credit, the Administrative Agent will make such Loans available to the Borrower by promptly making available the funds so received in the aforesaid account of the Administrative Agent by wire transfer of immediately available funds to an account of the Borrower designated by the Borrower in the applicable Borrowing Request; provided that ABR Revolving Loans made to finance the reimbursement of an LC Disbursement as provided in Section 2.06(e) shall be remitted by the Administrative Agent to the applicable Issuing Bank.

(b) Unless the Administrative Agent shall have received notice from a Lender prior to the proposed date of any Borrowing that such Lender will not make available to the Administrative Agent such Lender's share of such Borrowing, the Administrative Agent may assume that such Lender has made such share available on such date in accordance with paragraph (a) of this Section and may, in reliance upon such assumption, make available to the Borrower a corresponding amount. In such event, if a Lender has not in fact made its share of the applicable Borrowing available to the Administrative Agent, then the applicable Lender and the Borrower severally agree to pay to the Administrative Agent forthwith on demand such corresponding amount with interest thereon, for each day from and including the date such amount is made available to the Borrower to but excluding the date of payment to the Administrative Agent, at (i) in the case of such Lender, the greater of the NYFRB Rate and a rate determined by the Administrative Agent in accordance with banking industry rules on interbank compensation or (ii) in the case of the Borrower, the interest rate applicable to ABR Loans. If such Lender pays such amount to the Administrative Agent, then such amount shall constitute such Lender's Loan included in such Borrowing.

SECTION 2.08 Interest Elections. (a) Each Revolving Borrowing initially shall be of the Type specified in the applicable Borrowing Request and, in the case of a Term Benchmark Revolving Borrowing, shall have an initial Interest Period as specified in such Borrowing Request. Thereafter, the Borrower may elect to convert such Borrowing to a different Type or to continue such Borrowing and, in the case of a Term Benchmark Revolving Borrowing, may elect Interest Periods therefor, all as provided in this Section. The Borrower may elect different options with respect to different portions of the affected Borrowing, in which case each such portion shall be allocated ratably among the Lenders holding the Loans comprising such Borrowing, and the Loans comprising each such portion shall be considered a separate Borrowing. This Section shall not apply to Swingline Borrowings, which may not be converted or continued.

(b) To make an election pursuant to this Section, the Borrower shall notify the Administrative Agent of such election by the time that a Borrowing Request would be required under Section 2.03 if the Borrower were requesting a Revolving Borrowing of the Type resulting from such election to be made on the effective date of such election. Each such Interest Election Request shall be irrevocable and shall be signed by an Authorized Officer of the Borrower. Notwithstanding any contrary provision herein, this Section shall not be construed to permit the Borrower to elect an Interest Period for Term Benchmark Loans that does not comply with Section 2.02(d).

(c) Each Interest Election Request shall specify the following information in compliance with Section 2.02:

(i) the Borrowing to which such Interest Election Request applies and, if different options are being elected with respect to different portions thereof, the portions thereof to be allocated to each resulting Borrowing (in which case the information to be specified pursuant to clauses (iii) and (iv) below shall be specified for each resulting Borrowing);

(ii) the effective date of the election made pursuant to such Interest Election Request, which shall be a Business Day;

(iii) whether the resulting Borrowing is to be an ABR Borrowing or a Term Benchmark Borrowing or an RFR Borrowing; and

(iv) if the resulting Borrowing is a Term Benchmark Borrowing, the Interest Period to be applicable thereto after giving effect to such election, which Interest Period shall be a period contemplated by the definition of the term "Interest Period".

If any such Interest Election Request requests a Term Benchmark Borrowing but does not specify an Interest Period, then the Borrower shall be deemed to have selected an Interest Period of one month's duration. Notwithstanding the foregoing, in no event shall the Borrower be permitted to request an RFR Loan bearing interest based on Daily Simple SOFR prior to a Benchmark Transition Event and Benchmark Replacement Date with respect to the Term SOFR Rate (it being understood and agreed that Daily Simple SOFR shall only apply to the extent provided in Sections 2.14(a) and 2.14(f).

(d) Promptly following receipt of an Interest Election Request, the Administrative Agent shall advise each Lender of the details thereof and of such Lender's portion of each resulting Borrowing.

(e) If the Borrower fails to deliver a timely Interest Election Request with respect to a Term Benchmark Revolving Borrowing prior to the end of the Interest Period applicable thereto, then, unless such Borrowing is repaid as provided herein, at the end of such Interest Period such Borrowing shall be converted to an ABR Borrowing. Notwithstanding any contrary provision hereof, if an Event of Default has occurred and is continuing and the Administrative Agent, at the request of the Required Lenders, so notifies the Borrower, then, so long as an Event of Default is continuing (i) no outstanding Revolving Borrowing may be converted to or continued as a Term Benchmark Borrowing and (ii) unless repaid, each Term Benchmark Revolving Borrowing shall be converted to an ABR Borrowing at the end of the Interest Period applicable thereto.

(f) Notwithstanding anything in this Agreement or any other Loan Document to the contrary, interest on all "Term Benchmark Loans" outstanding immediately prior to the Amendment No. 1 Effective Date shall continue to accrue and be paid based upon the "LIBO Rate" applicable pursuant to the terms of the Credit Agreement immediately prior to the Amendment No. 1 Effective Date solely until the expiration of the current "Interest Period" (as defined in the Credit Agreement immediately prior to the Amendment No. 1 Effective Date and taking into account any grace periods or extensions of such "Interest Period" approved immediately prior to the Amendment No. 1 Effective Date) applicable thereto (at which time such Term Benchmark Loans may be reborrowed as Term Benchmark Borrowings or converted to ABR Borrowings in accordance with this section 2.08); provided, however, that from and after the Amendment No. 1 Effective Date, the Applicable Rate to be applied to any such Term Benchmark Loans shall be based on the Applicable Rate for Term Benchmark Loans after the Amendment No. 1 Effective Date.

SECTION 2.09 Termination and Reduction of Commitments. (a) Unless previously terminated, the Commitments shall terminate on the Maturity Date.

(b) The Borrower may at any time terminate, or from time to time reduce, the Commitments; provided that (i) each reduction of the Commitments shall be in an amount that is an integral multiple of $1,000,000 and not less than $5,000,000 and (ii) the Borrower shall not terminate or reduce the Commitments if, after giving effect to any concurrent prepayment of the Loans in accordance with Section 2.11, the Total Revolving Credit Exposure would exceed the Aggregate Commitment.

(c) The Borrower shall notify the Administrative Agent of any election to terminate or reduce the Commitments under paragraph (b) of this Section at least three (3) Business Days prior to the effective date of such termination or reduction, specifying such election and the effective date thereof. Promptly following receipt of any notice, the Administrative Agent shall advise the Lenders of the contents thereof. Each notice delivered by the Borrower pursuant to this Section shall be irrevocable; provided that a notice of termination of the Commitments delivered by the Borrower may state that such notice is conditioned upon the effectiveness of other credit facilities or other transactions specified therein, in which case such notice may be revoked by the Borrower (by notice to the Administrative Agent on or prior to the specified effective date) if such condition is not satisfied. Any termination or reduction of the Commitments shall be permanent. Each reduction of the Commitments shall be made ratably among the Lenders in accordance with their respective Commitments.

SECTION 2.10 Repayment of Loans; Evidence of Debt. (a) The Borrower hereby unconditionally promises to pay (i) to the Administrative Agent for the account of each Lender the then unpaid principal amount of each Revolving Loan on the Maturity Date and (ii) to the Administrative Agent for the account of the Swingline Lender the then unpaid principal amount of each Swingline Loan on the earliest of (x) the Maturity Date, (y) the fifth Business Day after the date such Swingline Loan was made and (z) the date required to maintain compliance with the proviso to the last sentence of Section 2.05(a); provided that on each date that a Revolving Borrowing is made, the Borrower shall repay all Swingline Loans then outstanding and the proceeds of any such Borrowing shall be applied by the Administrative Agent to repay any Swingline Loans outstanding.

(b) Each Lender shall maintain in accordance with its usual practice an account or accounts evidencing the indebtedness of the Borrower to such Lender resulting from each Loan made by such Lender, including the amounts of principal and interest payable and paid to such Lender from time to time hereunder.

(c) The Administrative Agent shall maintain accounts in which it shall record (i) the amount of each Loan made hereunder, the Class and Type thereof and the Interest Period applicable thereto, (ii) the amount of any principal or interest due and payable or to become due and payable from the Borrower to each Lender hereunder and (iii) the amount of any sum received by the Administrative Agent hereunder for the account of the Lenders and each Lender's share thereof.

(d) The entries made in the accounts maintained pursuant to paragraph (b) or (c) of this Section shall be prima facie evidence of the existence and amounts of the obligations recorded therein; provided that the failure of any Lender or the Administrative Agent to maintain such accounts or any error therein shall not in any manner affect the obligation of the Borrower to repay the Loans in accordance with the terms of this Agreement.

(e) Any Lender may request that Loans made by it be evidenced by a promissory note. In such event, the Borrower shall prepare, execute and deliver to such Lender a promissory note payable to such Lender (or, if requested by such Lender, to such Lender and its registered assigns) and in a form approved by the Administrative Agent. Thereafter, the Loans evidenced by such promissory note and interest thereon shall at all times (including after assignment pursuant to Section 9.04) be represented by one or more promissory notes in such form.

SECTION 2.11 Prepayment of Loans. The Borrower shall have the right at any time and from time to time to prepay any Borrowing in whole or in part, subject to prior notice in accordance with the provisions of this Section 2.11. The Borrower shall notify the Administrative Agent by telephone (confirmed by telecopy or electronic mail) of any prepayment hereunder (i) in the case of prepayment of (x) a Term Benchmark Revolving Borrowing, not later than 11:00 a.m., New York City time, three (3) Business Days before the date of prepayment or (y) an RFR Revolving Borrowing , not later than 11:00 a.m. New York City time, five (5) Business Days before the date of prepayment, (ii) in the case of prepayment of an ABR Revolving Borrowing, not later than 11:00 a.m., New York City time, one (1) Business Day before the date of prepayment. Each such notice shall be irrevocable and shall specify the prepayment date and the principal amount of each Borrowing or portion thereof to be prepaid; provided that, if a notice of prepayment is given in connection with a conditional notice of termination of the Commitments as contemplated by Section 2.09, then such notice of prepayment may be revoked if such notice of termination is revoked in accordance with Section 2.09. Promptly following receipt of any such notice relating to a Revolving Borrowing, the Administrative Agent shall advise the Lenders of the contents thereof. Each partial prepayment of any Revolving Borrowing shall be in an amount that would be permitted in the case of an advance of a Revolving Borrowing of the same Type as provided in Section 2.02. Each prepayment of a Revolving Borrowing shall be applied ratably to the Loans included in the prepaid Borrowing. Prepayments shall be accompanied by (i) accrued interest to the extent required by Section 2.13 and (ii) break funding payments pursuant to Section 2.16. If at any time the sum of the aggregate principal amount of all of the Revolving Credit Exposures exceeds the Aggregate Commitment, the Borrower shall immediately repay Borrowings or cash collateralize LC Exposure in an account with the Administrative Agent pursuant to Section 2.06(j), as applicable, in an aggregate principal amount sufficient to cause the aggregate principal amount of all Revolving Credit Exposures to be less than or equal to the Aggregate Commitment.

SECTION 2.12 Fees. (a) The Borrower agrees to pay to the Administrative Agent for the account of each Lender a facility fee, which shall accrue at the Applicable Rate on the daily amount of the Commitment of such Lender (whether used or unused) during the period from and including the Restatement Effective Date to but excluding the date on which such Commitment terminates; provided that, if such Lender continues to have any Revolving Credit Exposure after its Commitment terminates, then such facility fee shall continue to accrue on the daily amount of such Lender's Revolving Credit Exposure from and including the date on which its Commitment terminates to but excluding the date on which such Lender ceases to have any Revolving Credit Exposure. Facility fees accrued through and including the last day of March, June, September and December of each year shall be payable in arrears on the fifteenth day following the such last day and on the date on which the Commitments terminate, commencing on the first such date to occur after the date hereof; provided that any facility fees accruing after the date on which the Commitments terminate shall be payable on demand. All facility fees shall be computed on the basis of a year of 360 days and shall be payable for the actual number of days elapsed (including the first day but excluding the last day).

(b) The Borrower agrees to pay (i) to the Administrative Agent for the account of each Lender a participation fee with respect to its participations in Letters of Credit, which shall accrue at the same Applicable Rate used to determine the interest rate applicable to Term Benchmark Revolving Loans on the average daily amount of such Lender's LC Exposure (excluding any portion thereof attributable to unreimbursed LC Disbursements) during the period from and including the Restatement Effective Date to but excluding the later of the date on which such Lender's Commitment terminates and the date on which such Lender ceases to have any LC Exposure and (ii) to each Issuing Bank for its own account a fronting fee, which shall accrue at the rate or rates per annum separately agreed upon between the Borrower and such Issuing Bank on the average daily amount of the LC Exposure (excluding any portion thereof attributable to unreimbursed LC Disbursements) attributable to Letters of Credit issued by such Issuing Bank during the period from and including the Restatement Effective Date to but excluding the later of the date of termination of the Commitments and the date on which there ceases to be any LC Exposure, as well as such Issuing Bank's standard fees and commissions with respect to the issuance, amendment, cancellation, negotiation, transfer, presentment, renewal or extension of any Letter of Credit or processing of drawings thereunder. Participation fees and fronting fees accrued through and including the last day of March, June, September and December of each year shall be payable on the fifteenth day following such last day, commencing on the first such date to occur after the Restatement Effective Date; provided that all such fees shall be payable on the date on which the Commitments terminate and any such fees accruing after the date on which the Commitments terminate shall be payable on demand. Any other fees payable to any Issuing Bank pursuant to this paragraph shall be payable within ten (10) days after demand. All participation fees and fronting fees shall be computed on the basis of a year of 360 days and shall be payable for the actual number of days elapsed (including the first day but excluding the last day).

(c) The Borrower agrees to pay to the Administrative Agent, for its own account, fees payable in the amounts and at the times separately agreed upon between the Borrower and the Administrative Agent.

(d) All fees payable hereunder shall be paid on the dates due, in immediately available funds, to the Administrative Agent (or to an Issuing Bank, in the case of fees payable to it) for distribution, in the case of facility fees and participation fees, to the Lenders. Fees paid shall not be refundable under any circumstances.

SECTION 2.13 Interest. (a) The Loans comprising each ABR Borrowing (including each Swingline Loan) shall bear interest at the Alternate Base Rate plus the Applicable Rate.

(b) The Loans comprising each Term Benchmark Borrowing shall bear interest at the Adjusted Term SOFR Rate for the Interest Period in effect for such Borrowing plus the Applicable Rate.

(c) Each RFR Loan shall bear interest at a rate per annum equal to the Adjusted Daily Simple SOFR plus the Applicable Rate.

(d) Notwithstanding the foregoing, if any principal of or interest on any Loan or any fee or other amount payable by the Borrower hereunder is not paid when due, whether at stated maturity, upon acceleration or otherwise, such overdue amount shall bear interest, after as well as before judgment, at a rate per annum equal to (i) in the case of overdue principal of any Loan, 2% plus the rate otherwise applicable to such Loan as provided in the preceding paragraphs of this Section or (ii) in the case of any other amount, 2% plus the rate applicable to ABR Loans as provided in paragraph (a) of this Section.

(e) Accrued interest on each Loan shall be payable in arrears on each Interest Payment Date for such Loan and, in the case of Revolving Loans, upon termination of the Commitments; provided that (i) interest accrued pursuant to paragraph (d) of this Section shall be payable on demand, (ii) in the event of any repayment or prepayment of any Loan (other than a prepayment of an ABR Revolving Loan prior to the end of the Availability Period), accrued interest on the principal amount repaid or prepaid shall be payable on the date of such repayment or prepayment and (iii) in the event of any conversion of any Term Benchmark Revolving Loan prior to the end of the current Interest Period therefor, accrued interest on such Loan shall be payable on the effective date of such conversion.

(f) All interest hereunder shall be computed on the basis of a year of 360 days, except that interest computed by reference to the Alternate Base Rate at times when the Alternate Base Rate is based on the Prime Rate shall be computed on the basis of a year of 365 days (or 366 days in a leap year), and in each case shall be payable for the actual number of days elapsed (including the first day but excluding the last day). The applicable Alternate Base Rate, Term SOFR Rate, Adjusted Daily Simple SOFR or Daily Simple SOFR shall be determined by the Administrative Agent, and such determination shall be conclusive absent manifest error.

SECTION 2.14 Alternate Rate of Interest.

(a) Subject to clauses (b) (c), (d), (e), and (f) of this Section 2.14, if:

(i) the Administrative Agent determines (which determination shall be conclusive and binding absent manifest error) (A) prior to the commencement of any Interest Period for a Term Benchmark Borrowing, that adequate and reasonable means do not exist for ascertaining the Adjusted Term SOFR Rate (including because the Term SOFR Reference Rate is not available or published on a current basis), for such Interest Period or (B) at any time, that adequate and reasonable means do not exist for ascertaining the applicable Adjusted Daily Simple SOFR; or

(ii) the Administrative Agent is advised by the Required Lenders that (A) prior to the commencement of any Interest Period for a Term Benchmark Borrowing, the Adjusted Term SOFR Rate for such Interest Period will not adequately and fairly reflect the cost to such Lenders of making or maintaining their Loans included in such Borrowing for such Interest Period or (B) at any time, Adjusted Daily Simple SOFR will not adequately and fairly reflect the cost to such Lenders of making or maintaining their Loans included in such Borrowing;

then the Administrative Agent shall give notice thereof to the Borrower and the Lenders by telephone, telecopy or electronic mail as promptly as practicable thereafter and, until (x) the Administrative Agent notifies the Borrower and the Lenders that the circumstances giving rise to such notice no longer exist with respect to the relevant Benchmark and (y) the Borrower delivers a new Interest Election Request in accordance with the terms of Section 2.08 or a new Borrowing Request in accordance with the terms of Section 2.03, (1) any Interest Election Request that requests the conversion of any Borrowing to, or continuation of any Borrowing as, a Term Benchmark Borrowing and any Borrowing Request that requests a Term Benchmark Borrowing, such Borrowing shall instead be deemed to be an Interest Election Request or a Borrowing Request, as applicable, for (x) an RFR Borrowing so long as the Adjusted Daily Simple SOFR is not also the subject of Section 2.14(a)(i) or (ii) above or (y) an ABR Borrowing if the Adjusted Daily Simple SOFR also is the subject of Section 2.14(a)(i) or (ii) above and (2) any Borrowing Request that requests an RFR Borrowing shall instead be deemed to be a Borrowing Request, as applicable, for an ABR Borrowing if the Adjusted Daily Simple SOFR also is the subject of Section 2.14(a)(i) or (ii) above; provided that if the circumstances giving rise to such notice affect only one Type of Borrowings, then all other Types of Borrowings shall be permitted. Furthermore, if any Term Benchmark Loan or RFR Loan is outstanding on the date of the Borrower's receipt of the notice from the Administrative Agent referred to in this Section 2.14(a) with respect to a Relevant Rate applicable to such Term Benchmark Loan or RFR Loan, then until (x) the Administrative Agent notifies the Borrower and the Lenders that the circumstances giving rise to such notice no longer exist, with respect to the relevant Benchmark and (y) the Borrower delivers a new Interest Election Request in accordance with the terms of Section 2.03, (1) any Term Benchmark Loan shall on the last day of the Interest Period applicable to such Loan be converted by the Administrative Agent to, and shall constitute, (x) an RFR Borrowing so long as the Adjusted Daily Simple SOFR is not also the subject of Section 2.14(a)(i) or (ii) above or (y) an ABR Loan if the Adjusted Daily Simple SOFR also is the subject of Section 2.14(a)(i) or (ii) above, on such day, and (2) any such RFR Loan shall on and from such day be converted by the Administrative Agent to, and shall constitute an ABR Loan.

(b) Notwithstanding anything to the contrary herein or in any other Loan Document (and any Swap Agreement shall be deemed not to be a "Loan Document" for purposes of this Section 2.14), if a Benchmark Transition Event and its related Benchmark Replacement Date have occurred prior to the Reference Time in respect of any setting of the then-current Benchmark, then (x) if a Benchmark Replacement is determined in accordance with clause (1) of the definition of "Benchmark Replacement" for such Benchmark Replacement Date, such Benchmark Replacement will replace such Benchmark for all purposes hereunder and under any Loan Document in respect of such Benchmark setting and subsequent Benchmark settings without any amendment to, or further action or consent of any other party to, this Agreement or any other Loan Document and (y) if a Benchmark Replacement is determined in accordance with clause (2) of the definition of "Benchmark Replacement" for such Benchmark Replacement Date, such Benchmark Replacement will replace such Benchmark for all purposes hereunder and under any Loan Document in respect of any Benchmark setting at or after 5:00 p.m. (New York City time) on the fifth (5th) Business Day after the date notice of such Benchmark Replacement is provided to the Lenders without any amendment to, or further action or consent of any other party to, this Agreement or any other Loan Document so long as the Administrative Agent has not received, by such time, written notice of objection to such Benchmark Replacement from Lenders comprising the Required Lenders.

(c) Notwithstanding anything to the contrary herein or in any other Loan Document, the Administrative Agent will have the right to make Benchmark Replacement Conforming Changes from time to time and, notwithstanding anything to the contrary herein or in any other Loan Document, any amendments implementing such Benchmark Replacement Conforming Changes will become effective without any further action or consent of any other party to this Agreement or any other Loan Document.

(d) The Administrative Agent will promptly notify the Borrower and the Lenders of (i) any occurrence of a Benchmark Transition Event (ii) the implementation of any Benchmark Replacement, (iii) the effectiveness of any Benchmark Replacement Conforming Changes, (iv) the removal or reinstatement of any tenor of a Benchmark pursuant to clause (e) below and (v) the commencement or conclusion of any Benchmark Unavailability Period. Any determination, decision or election that may be made by the Administrative Agent or, if applicable, any Lender (or group of Lenders) pursuant to this Section 2.14, including any determination with respect to a tenor, rate or adjustment or of the occurrence or non-occurrence of an event, circumstance or date and any decision to take or refrain from taking any action or any selection, will be conclusive and binding absent manifest error and may be made in its or their sole discretion and without consent from any other party to this Agreement or any other Loan Document, except, in each case, as expressly required pursuant to this Section 2.14.

(e) Notwithstanding anything to the contrary herein or in any other Loan Document, at any time (including in connection with the implementation of a Benchmark Replacement), (i) if the then-current Benchmark is a term rate (including the Term SOFR Rate) and either (A) any tenor for such Benchmark is not displayed on a screen or other information service that publishes such rate from time to time as selected by the Administrative Agent in its reasonable discretion or (B) the regulatory supervisor for the administrator of such Benchmark has provided a public statement or publication of information announcing that any tenor for such Benchmark is or will be no longer representative, then the Administrative Agent may modify the definition of "Interest Period" for any Benchmark settings at or after such time to remove such unavailable or non-representative tenor and (ii) if a tenor that was removed pursuant to clause (i) above either (A) is subsequently displayed on a screen or information service for a Benchmark (including a Benchmark Replacement) or (B) is not, or is no longer, subject to an announcement that it is or will no longer be representative for a Benchmark (including a Benchmark Replacement), then the Administrative Agent may modify the definition of "Interest Period" for all Benchmark settings at or after such time to reinstate such previously removed tenor.

(f) Upon the Borrower's receipt of notice of the commencement of a Benchmark Unavailability Period, the Borrower may revoke any request for a Term Benchmark Borrowing or RFR Borrowing of, conversion to or continuation of Term Benchmark Loans or RFR Loans to be made, converted or continued during any Benchmark Unavailability Period and, failing that, the Borrower will be deemed to have converted any such request for a Term Benchmark Borrowing into a request for a Borrowing of or conversion to (A) an RFR Borrowing so long as the Adjusted Daily Simple SOFR is not the subject of a Benchmark Transition Event or (B) an ABR Borrowing if the Adjusted Daily Simple SOFR is the subject of a Benchmark Transition Event. During any Benchmark Unavailability Period or at any time that a tenor for the then-current Benchmark is not an Available Tenor, the component of ABR based upon the then-current Benchmark or such tenor for such Benchmark, as applicable, will not be used in any determination of ABR. Furthermore, if any Term Benchmark Loan or RFR Loan is outstanding on the date of the Borrower's receipt of notice of the commencement of a Benchmark Unavailability Period with respect to a Relevant Rate applicable to such Term Benchmark Loan or RFR Loan, then until such time as a Benchmark Replacement is implemented pursuant to this Section 2.14, (1) any Term Benchmark Loan shall on the last day of the Interest Period applicable to such Loan, be converted by the Administrative Agent to, and shall constitute, (x) an RFR Borrowing so long as the Adjusted Daily Simple SOFR is not the subject of a Benchmark Transition Event or (y) an ABR Loan if the Adjusted Daily Simple SOFR is the subject of a Benchmark Transition Event, on such date and (2) any such RFR Loan shall on and from such day, be converted by the Administrative Agent to, and shall constitute an ABR Loan.

SECTION 2.15 Increased Costs. (a) If any Change in Law shall:

(i) impose, modify or deem applicable any reserve, special deposit, liquidity or similar requirement (including any compulsory loan requirement, insurance charge or other assessment) against assets of, deposits with or for the account of, or credit extended by, any Lender or any Issuing Bank;

(ii) impose on any Lender or any Issuing Bank or the applicable offshore interbank market any other condition, cost or expense (other than Taxes) affecting this Agreement or Loans made by such Lender or any Letter of Credit or participation therein; or

(iii) subject any Recipient to any Taxes (other than (A) Indemnified Taxes, (B) Taxes described in clauses (b) through (d) of the definition of Excluded Taxes and (C) Connection Income Taxes) on its loans, loan principal, letters of credit, commitments, or other obligations, or its deposits, reserves, other liabilities or capital attributable thereto;

and the result of any of the foregoing shall be to increase the cost to such Lender or such other Recipient of making, continuing, converting into or maintaining any Loan or of maintaining its obligation to make any such Loan or to increase the cost to such Lender, such Issuing Bank or such other Recipient of participating in, issuing or maintaining any Letter of Credit or to reduce the amount of any sum received or receivable by such Lender, such Issuing Bank or such other Recipient hereunder, whether of principal, interest or otherwise, then the Borrower will pay to such Lender, such Issuing Bank or such other Recipient, as the case may be, such additional amount or amounts as will compensate such Lender, such Issuing Bank or such other Recipient, as the case may be, for such additional costs incurred or reduction suffered.

(b) If any Lender or any Issuing Bank determines that any Change in Law regarding capital or liquidity requirements has or would have the effect of reducing the rate of return on such Lender's or such Issuing Bank's capital or on the capital of such Lender's or such Issuing Bank's holding company, if any, as a consequence of this Agreement or the Loans made by, or participations in Letters of

Credit or Swingline Loans held by, such Lender, or the Letters of Credit issued by such Issuing Bank, to a level below that which such Lender or such Issuing Bank or such Lender's or such Issuing Bank's holding company could have achieved but for such Change in Law (taking into consideration such Lender's or such Issuing Bank's policies and the policies of such Lender's or such Issuing Bank's holding company with respect to capital adequacy and liquidity), then from time to time the Borrower will pay to such Lender or such Issuing Bank, as the case may be, such additional amount or amounts as will compensate such Lender or such Issuing Bank or such Lender's or such Issuing Bank's holding company for any such reduction suffered.

(c) A certificate of a Lender or an Issuing Bank setting forth the amount or amounts necessary to compensate such Lender or such Issuing Bank or its holding company, as the case may be, as specified in paragraph (a) or (b) of this Section shall be delivered to the Borrower and shall be conclusive absent manifest error. The Borrower shall pay such Lender or such Issuing Bank, as the case may be, the amount shown as due on any such certificate within ten (10) days after receipt thereof.

(d) Failure or delay on the part of any Lender or any Issuing Bank to demand compensation pursuant to this Section shall not constitute a waiver of such Lender's or such Issuing Bank's right to demand such compensation; provided that the Borrower shall not be required to compensate a Lender or an Issuing Bank pursuant to this Section for any increased costs or reductions incurred more than 270 days prior to the date that such Lender or such Issuing Bank, as the case may be, notifies the Borrower of the Change in Law giving rise to such increased costs or reductions and of such Lender's or such Issuing Bank's intention to claim compensation therefor; provided further that, if the Change in Law giving rise to such increased costs or reductions is retroactive, then the 270-day period referred to above shall be extended to include the period of retroactive effect thereof.

SECTION 2.16 Break Funding Payments. With respect to Loans that are not RFR Loans, in the event of (i) the payment of any principal of any Term Benchmark Loan other than on the last day of an Interest Period applicable thereto (including as a result of an Event of Default or an optional prepayment of Loans pursuant to Section 2.11), (ii) the conversion of any Term Benchmark Loan other than on the last day of the Interest Period applicable thereto, (iii) the failure to borrow, convert, continue or prepay any Term Benchmark Loan on the date specified in any notice delivered pursuant hereto (regardless of whether such notice may be revoked under Section 2.11 and is revoked in accordance therewith) or (iv) the assignment of any Term Benchmark Loan other than on the last day of the Interest Period applicable thereto as a result of a request by the Borrower pursuant to Section 2.19, then, in any such event, the Borrower shall compensate each Lender for the loss, cost and expense attributable to such event. A certificate of any Lender setting forth any amount or amounts that such Lender is entitled to receive pursuant to this Section shall be delivered to the Borrower and shall be conclusive absent manifest error. The Borrower shall pay such Lender the amount shown as due on any such certificate within ten (10) days after receipt thereof.

SECTION 2.17 Withholding of Taxes; Gross-Up. (a) Payments Free of Taxes. Any and all payments by or on account of any obligation of the Borrower under any Loan Document shall be made without deduction or withholding for any Taxes, except as required by applicable law. If any applicable law (as determined in the good faith discretion of an applicable withholding agent) requires the deduction or withholding of any Tax from any such payment by a withholding agent, then the applicable withholding agent shall be entitled to make such deduction or withholding and shall timely pay the full amount deducted or withheld to the relevant Governmental Authority in accordance with applicable law and, if such Tax is an Indemnified Tax, then the sum payable by the Borrower shall be increased as necessary so that after such deduction or withholding has been made (including such deductions and withholdings applicable to additional sums payable under this Section 2.17) the applicable Recipient receives an amount equal to the sum it would have received had no such deduction or withholding been made.

(b) Payment of Other Taxes by the Borrower. The Borrower shall timely pay to the relevant Governmental Authority in accordance with applicable law, or at the option of the Administrative Agent timely reimburse it for, Other Taxes.

(c) Evidence of Payments. As soon as practicable after any payment of Taxes by the Borrower to a Governmental Authority pursuant to this Section 2.17, the Borrower shall deliver to the Administrative Agent the original or a certified copy of a receipt issued by such Governmental Authority evidencing such payment, a copy of the return reporting such payment or other evidence of such payment reasonably satisfactory to the Administrative Agent.

(d) Indemnification by the Borrower. The Borrower shall indemnify each Recipient, within 10 days after demand therefor, for the full amount of any Indemnified Taxes (including Indemnified Taxes imposed or asserted on or attributable to amounts payable under this Section) payable or paid by such Recipient or required to be withheld or deducted from a payment to such Recipient and any reasonable expenses arising therefrom or with respect thereto, whether or not such Indemnified Taxes were correctly or legally imposed or asserted by the relevant Governmental Authority. A certificate as to the amount of such payment or liability delivered to the Borrower by a Lender (with a copy to the Administrative Agent), or by the Administrative Agent on its own behalf or on behalf of a Lender, shall be conclusive absent manifest error.

(e) Indemnification by the Lenders. Each Lender shall severally indemnify the Administrative Agent, within 10 days after demand therefor, for (i) any Indemnified Taxes attributable to such Lender (but only to the extent that the Borrower has not already indemnified the Administrative Agent for such Indemnified Taxes and without limiting the obligation of the Borrower to do so), (ii) any Taxes attributable to such Lender's failure to comply with the provisions of Section 9.04(c) relating to the maintenance of a Participant Register and (iii) any Excluded Taxes attributable to such Lender, in each case, that are payable or paid by the Administrative Agent in connection with any Loan Document, and any reasonable expenses arising therefrom or with respect thereto, whether or not such Taxes were correctly or legally imposed or asserted by the relevant Governmental Authority. A certificate as to the amount of such payment or liability delivered to any Lender by the Administrative Agent shall be conclusive absent manifest error. Each Lender hereby authorizes the Administrative Agent to set off and apply any and all amounts at any time owing to such Lender under any Loan Document or otherwise payable by the Administrative Agent to the Lender from any other source against any amount due to the Administrative Agent under this paragraph (e).

(f) Status of Lenders. (i) Any Lender that is entitled to an exemption from or reduction of withholding Tax with respect to payments made under any Loan Document shall deliver to the Borrower and the Administrative Agent, at the time or times reasonably requested by the Borrower or the Administrative Agent, such properly completed and executed documentation reasonably requested by the Borrower or the Administrative Agent as will permit such payments to be made without withholding or at a reduced rate of withholding. In addition, any Lender, if reasonably requested by the Borrower or the Administrative Agent, shall deliver such other documentation prescribed by applicable law or reasonably requested by the Borrower or the Administrative Agent as will enable the Borrower or the Administrative Agent to determine whether or not such Lender is subject to backup withholding or information reporting requirements. Notwithstanding anything to the contrary in the preceding two sentences, the completion, execution and submission of such documentation (other than such documentation set forth in Section 2.17(f)(ii)(A), (ii)(B) and (ii)(D) below) shall not be required if in the Lender's reasonable judgment such completion, execution or submission would subject such Lender to any material unreimbursed cost or expense or would materially prejudice the legal or commercial position of such Lender.

(ii) Without limiting the generality of the foregoing, in the event that the Borrower is a U.S. Person:

(A) any Lender that is a U.S. Person shall deliver to the Borrower and the Administrative Agent on or prior to the date on which such Lender becomes a Lender under this Agreement (and from time to time thereafter upon the reasonable request of the Borrower or the Administrative Agent), an executed copy of IRS Form W-9 certifying that such Lender is exempt from U.S. federal backup withholding tax;

(B) any Foreign Lender shall, to the extent it is legally entitled to do so, deliver to the Borrower and the Administrative Agent (in such number of copies as shall be requested by the recipient) on or prior to the date on which such Foreign Lender becomes a Lender under this Agreement (and from time to time thereafter upon the reasonable request of the Borrower or the Administrative Agent), whichever of the following is applicable:

(1) in the case of a Foreign Lender claiming the benefits of an income tax treaty to which the United States is a party (x) with respect to payments of interest under any Loan Document, an executed copy of IRS Form W-8BEN-E or IRS Form W-8BEN establishing an exemption from, or reduction of, U.S. federal withholding Tax pursuant to the "interest" article of such tax treaty and (y) with respect to any other applicable payments under any Loan Document, IRS Form W-8BEN-E or IRS Form W-8BEN establishing an exemption from, or reduction of, U.S. Federal withholding Tax pursuant to the "business profits" or "other income" article of such tax treaty;

(2) in the case of a Foreign Lender claiming that its extension of credit will generate U.S. effectively connected income, an executed copy of IRS Form W-8ECI;

(3) in the case of a Foreign Lender claiming the benefits of the exemption for portfolio interest under Section 881(c) of the Code, (x) a certificate substantially in the form of Exhibit E-1 to the effect that such Foreign Lender is not a "bank" within the meaning of Section 881(c)(3)(A) of the Code, a "10 percent shareholder" of the Borrower within the meaning of Section 881(c)(3)(B) of the Code, or a "controlled foreign corporation" described in Section 881(c)(3)(C) of the Code (a "U.S. Tax Compliance Certificate") and (y) an executed copy of IRS Form W-8BEN-E or IRS Form W-8BEN; or

(4) to the extent a Foreign Lender is not the beneficial owner, an executed copy of IRS Form W-8IMY, accompanied by IRS Form W-8ECI, IRS Form W-8BEN-E or IRS Form W-8BEN, a U.S. Tax Compliance Certificate substantially in the form of Exhibit E-2 or Exhibit E-3, IRS Form W-9, and/or other certification documents from each beneficial owner, as applicable; provided that if the Foreign Lender is a partnership and one or more direct or indirect partners of such Foreign Lender are claiming the portfolio interest exemption, such Foreign Lender may provide a U.S. Tax Compliance Certificate substantially in the form of Exhibit E-4 on behalf of each such direct and indirect partner;

(C) any Foreign Lender shall, to the extent it is legally entitled to do so, deliver to the Borrower and the Administrative Agent (in such number of copies as shall be requested by the recipient) on or prior to the date on which such Foreign Lender becomes a Lender under this Agreement (and from time to time thereafter upon the reasonable request of the Borrower or the Administrative Agent), executed copies of any other form prescribed by applicable law as a basis for claiming exemption from or a reduction in U.S. Federal withholding Tax, duly completed, together with such supplementary documentation as may be prescribed by applicable law to permit the Borrower or the Administrative Agent to determine the withholding or deduction required to be made; and

(D) if a payment made to a Lender under any Loan Document would be subject to U.S. federal withholding Tax imposed by FATCA if such Lender were to fail to comply with the applicable reporting requirements of FATCA (including those contained in Section 1471(b) or 1472(b) of the Code, as applicable), such Lender shall deliver to the Borrower and the Administrative Agent at the time or times prescribed by law and at such time or times reasonably requested by the Borrower or the Administrative Agent such documentation prescribed by applicable law (including as prescribed by Section 1471(b)(3)(C)(i) of the Code) and such additional documentation reasonably requested by the Borrower or the Administrative Agent as may be necessary for the Borrower and the Administrative Agent to comply with their obligations under FATCA and to determine that such Lender has complied with such Lender's obligations under FATCA or to determine the amount to deduct and withhold from such payment. Solely for purposes of this clause (D), "FATCA" shall include any amendments made to FATCA after the date of this Agreement.

Each Lender agrees that if any form or certification it previously delivered expires or becomes obsolete or inaccurate in any respect, it shall update such form or certification or promptly notify the Borrower and the Administrative Agent in writing of its legal inability to do so.

(g) Treatment of Certain Refunds. If any party determines, in its sole discretion exercised in good faith, that it has received a refund of any Taxes as to which it has been indemnified pursuant to this Section 2.17 (including by the payment of additional amounts pursuant to this Section 2.17), it shall pay to the indemnifying party an amount equal to such refund (but only to the extent of indemnity payments made under this Section 2.17 with respect to the Taxes giving rise to such refund), net of all out-of-pocket expenses (including Taxes) of such indemnified party and without interest (other than any interest paid by the relevant Governmental Authority with respect to such refund). Such indemnifying party, upon the request of such indemnified party, shall repay to such indemnified party the amount paid over pursuant to this paragraph (g) (plus any penalties, interest or other charges imposed by the relevant Governmental Authority) in the event that such indemnified party is required to repay such refund to such Governmental Authority. Notwithstanding anything to the contrary in this paragraph (g), in no event will the indemnified party be required to pay any amount to an indemnifying party pursuant to this paragraph (g) the payment of which would place the indemnified party in a less favorable net after-Tax position than the indemnified party would have been in if the Tax subject to indemnification and giving rise to such refund had not been deducted, withheld or otherwise imposed and the indemnification payments or additional amounts with respect to such Tax had never been paid. This paragraph shall not be construed to require any indemnified party to make available its Tax returns (or any other information relating to its Taxes that it deems confidential) to the indemnifying party or any other Person.

(h) Survival. Each party's obligations under this Section 2.17 shall survive the resignation or replacement of the Administrative Agent or any assignment of rights by, or the replacement of, a Lender, the termination of the Commitments and the repayment, satisfaction or discharge of all obligations under any Loan Document.

(i) Defined Terms. For purposes of this Section 2.17, the term "Lender" includes the Issuing Banks and the term "applicable law" includes FATCA.

SECTION 2.18 Payments Generally; Pro Rata Treatment; Sharing of Set-offs. (a) The Borrower shall make each payment required to be made by it hereunder (whether of principal, interest, fees or reimbursement of LC Disbursements, or of amounts payable under Section 2.15, 2.16 or 2.17, or otherwise) prior to 12:00 noon, New York City time on the date when due, in immediately available funds, without set-off, recoupment or counterclaim. Any amounts received after such time on any date may, in the discretion of the Administrative Agent, be deemed to have been received on the next succeeding Business Day for purposes of calculating interest thereon. All such payments shall be made to the Administrative Agent at its offices as specified in Section 9.01(a)(ii), except payments to be made directly to an Issuing Bank or Swingline Lender as expressly provided herein and except that payments pursuant to Sections 2.15, 2.16, 2.17 and 9.03 shall be made directly to the Persons entitled thereto. The Administrative Agent shall distribute any such payments received by it for the account of any other Person to the appropriate recipient promptly following receipt thereof. If any payment hereunder shall be due on a day that is not a Business Day, the date for payment shall be extended to the next succeeding Business Day, and, in the case of any payment accruing interest, interest thereon shall be payable for the period of such extension. All payments hereunder shall be made in Dollars.

(b) If at any time insufficient funds are received by and available to the Administrative Agent to pay fully all amounts of principal, unreimbursed LC Disbursements, interest and fees then due hereunder, such funds shall be applied (i) first, towards payment of interest and fees then due hereunder, ratably among the parties entitled thereto in accordance with the amounts of interest and fees then due to such parties, and (ii) second, towards payment of principal and unreimbursed LC Disbursements then due hereunder, ratably among the parties entitled thereto in accordance with the amounts of principal and unreimbursed LC Disbursements then due to such parties.

(c) If any Lender shall, by exercising any right of set-off or counterclaim or otherwise, obtain payment in respect of any principal of or interest on any of its Revolving Loans or participations in LC Disbursements or Swingline Loans resulting in such Lender receiving payment of a greater proportion of the aggregate amount of its Revolving Loans and participations in LC Disbursements and Swingline Loans and accrued interest thereon than the proportion received by any other Lender, then the Lender receiving such greater proportion shall purchase (for cash at face value) participations in the Revolving Loans and participations in LC Disbursements and Swingline Loans of other Lenders to the extent necessary so that the benefit of all such payments shall be shared by the Lenders ratably in accordance with the aggregate amount of principal of and accrued interest on their respective Revolving Loans and participations in LC Disbursements and Swingline Loans; provided that (i) if any such participations are purchased and all or any portion of the payment giving rise thereto is recovered, such participations shall be rescinded and the purchase price restored to the extent of such recovery, without interest, and (ii) the provisions of this paragraph shall not be construed to apply to any payment made by the Borrower pursuant to and in accordance with the express terms of this Agreement or any payment obtained by a Lender as consideration for the assignment of or sale of a participation in any of its Loans or participations in LC Disbursements and Swingline Loans to any assignee or participant, other than to the Borrower or any Subsidiary or Affiliate thereof (as to which the provisions of this paragraph shall apply). The Borrower consents to the foregoing and agrees, to the extent it may effectively do so under applicable law, that any Lender acquiring a participation pursuant to the foregoing arrangements may exercise against the Borrower rights of set-off and counterclaim with respect to such participation as fully as if such Lender were a direct creditor of the Borrower in the amount of such participation.

(d) Unless the Administrative Agent shall have received notice from the Borrower prior to the date on which any payment is due to the Administrative Agent for the account of the Lenders or the Issuing Banks hereunder that the Borrower will not make such payment, the Administrative Agent may assume that the Borrower has made such payment on such date in accordance herewith and may, in reliance upon such assumption, distribute to the Lenders or the Issuing Banks, as the case may be, the amount due. In such event, if the Borrower has not in fact made such payment, then each of the Lenders or the Issuing Banks, as the case may be, severally agrees to repay to the Administrative Agent forthwith on demand the amount so distributed to such Lender or such Issuing Bank with interest thereon, for each day from and including the date such amount is distributed to it to but excluding the date of payment to the Administrative Agent, at the NYFRB Rate.

SECTION 2.19 Mitigation Obligations; Replacement of Lenders. (a) If any Lender requests compensation under Section 2.15, or the Borrower is required to pay any Indemnified Taxes or additional amounts to any Lender or any Governmental Authority for the account of any Lender pursuant to Section 2.17, then such Lender shall use reasonable efforts to designate a different lending office for funding or booking its Loans hereunder or to assign its rights and obligations hereunder to another of its offices, branches or Affiliates, if, in the judgment of such Lender, such designation or assignment (i) would eliminate or reduce amounts payable pursuant to Section 2.15 or 2.17, as the case may be, in the future and (ii) would not subject such Lender to any unreimbursed cost or expense and would not otherwise be disadvantageous to such Lender. The Borrower hereby agrees to pay all reasonable costs and expenses incurred by any Lender in connection with any such designation or assignment.

(b) If any Lender requests compensation under Section 2.15, or if the Borrower is required to pay any Indemnified Taxes or additional amounts to any Lender or any Governmental Authority for the account of any Lender pursuant to Section 2.17, or if any Lender becomes a Defaulting Lender, or if any Lender does not consent to any proposed amendment, supplement, modification, consent or waiver of any provision of this Agreement or any other Loan Document that requires the consent of each of the Lenders or each of the Lenders affected thereby (so long as the consent of the Required Lenders (with the percentage in such definition being deemed to be 50% for this purpose) has been obtained), then the Borrower may, at its sole expense and effort, upon notice to such Lender and the

Administrative Agent, require such Lender to assign and delegate, without recourse (in accordance with and subject to the restrictions contained in Section 9.04), all its interests, rights (other than its existing rights to payments pursuant to Sections 2.15 or 2.17) and obligations under this Agreement and the other Loan Documents to an assignee that shall assume such obligations (which assignee may be another Lender, if a Lender accepts such assignment); provided that (i) the Borrower shall have received the prior written consent of the Administrative Agent (and if a Commitment is being assigned, the Issuing Banks and the Swingline Lender), which consent shall not unreasonably be withheld, (ii) such Lender shall have received payment of an amount equal to the outstanding principal of its Loans and participations in LC Disbursements and Swingline Loans, accrued interest thereon, accrued fees and all other amounts payable to it hereunder, from the assignee (to the extent of such outstanding principal and accrued interest and fees) or the Borrower (in the case of all other amounts) and (iii) in the case of any such assignment resulting from a claim for compensation under Section 2.15 or payments required to be made pursuant to Section 2.17, such assignment will result in a reduction in such compensation or payments. A Lender shall not be required to make any such assignment and delegation if, prior thereto, as a result of a waiver by such Lender or otherwise, the circumstances entitling the Borrower to require such assignment and delegation cease to apply. Each party hereto agrees that (a) an assignment required pursuant to this paragraph may be effected pursuant to an Assignment and Assumption executed by the Borrower, the Administrative Agent and the assignee (or, to the extent applicable, an agreement incorporating an Assignment and Assumption by reference pursuant to an Approved Electronic Platform as to which the Administrative Agent and such parties are participants), and (b) the Lender required to make such assignment need not be a party thereto in order for such assignment to be effective and shall be deemed to have consented to an be bound by the terms thereof; provided that, following the effectiveness of any such assignment, the other parties to such assignment agree to execute and deliver such documents necessary to evidence such assignment as reasonably requested by the applicable Lender, provided that any such documents shall be without recourse to or warranty by the parties thereto.

SECTION 2.20 Expansion Option. The Borrower may from time to time elect to increase the Commitments or enter into one or more tranches of term loans (each an "Incremental Term Loan"), in each case a minimum amount of $10,000,000 and any integral of $5,000,000 in excess thereof, so long as, after giving effect thereto, the aggregate amount of such increases and all such Incremental Term Loans does not exceed $200,000,000. The Borrower may arrange for any such increase or tranche to be provided by one or more Lenders (each Lender so agreeing to an increase in its Commitment, or to participate in such Incremental Term Loans, an "Increasing Lender"), or by one or more new banks, financial institutions or other entities (each such new bank, financial institution or other entity, an "Augmenting Lender"; provided that no Ineligible Institution may be an Augmenting Lender), which agree to increase their existing Commitments, or to participate in such Incremental Term Loans, or provide new Commitments, as the case may be; provided that (i) each Augmenting Lender, shall be subject to the approval of the Borrower, the Administrative Agent and the Issuing Banks and the Swingline Lender to the extent the consent of the Issuing Banks or the Swingline Lender would be required to effect an assignment under Section 9.04(b), and (ii) (x) in the case of an Increasing Lender, the Borrower and such Increasing Lender execute an agreement substantially in the form of Exhibit B hereto, and (y) in the case of an Augmenting Lender, the Borrower and such Augmenting Lender execute an agreement substantially in the form of Exhibit C hereto. No consent of any Lender (other than the Lenders participating in the increase or any Incremental Term Loan) shall be required for any increase in Commitments or Incremental Term Loan pursuant to this Section 2.20. Increases and new Commitments and Incremental Term Loans created pursuant to this Section 2.20 shall become effective on the date agreed by the Borrower, the Administrative Agent and the relevant Increasing Lenders or Augmenting Lenders, and the Administrative Agent shall notify each Lender thereof. Notwithstanding the foregoing, no increase in the Commitments (or in the Commitment of any Lender) or tranche of Incremental Term Loans shall become effective under this paragraph unless, (i) on the proposed date of the effectiveness of such increase or Incremental Term Loans, (A) the conditions set forth in paragraphs (a) and (b) of Section 4.02 shall be satisfied or waived by the Required Lenders and the Administrative Agent shall have received a certificate to that effect dated such date and executed by a Financial Officer of the Borrower and (B) the Borrower shall be in compliance (on a pro forma basis) with the covenants contained in Section 6.02 and (ii) the Administrative Agent shall have received documents and opinions consistent with those delivered on the Restatement Effective Date as to the organizational power and authority of the Borrower to borrow hereunder after giving effect to such increase. On the effective date of any increase in the Commitments or any Incremental Term Loans being made, (i) each relevant

Increasing Lender and Augmenting Lender shall make available to the Administrative Agent such amounts in immediately available funds as the Administrative Agent shall determine, for the benefit of the other Lenders, as being required in order to cause, after giving effect to such increase and the use of such amounts to make payments to such other Lenders, each Lender's portion of the outstanding Revolving Loans of all the Lenders to equal its Applicable Percentage of such outstanding Revolving Loans, and (ii) except in the case of any Incremental Term Loans, the Borrower shall be deemed to have repaid and reborrowed all outstanding Revolving Loans as of the date of any increase in the Commitments (with such reborrowing to consist of the Types of Revolving Loans, with related Interest Periods if applicable, specified in a notice delivered by the Borrower, in accordance with the requirements of Section 2.03). The deemed payments made pursuant to clause (ii) of the immediately preceding sentence shall be accompanied by payment of all accrued interest on the amount prepaid and, in respect of each Term Benchmark Loan, shall be subject to indemnification by the Borrower pursuant to the provisions of Section 2.16 if the deemed payment occurs other than on the last day of the related Interest Periods. The Incremental Term Loans (a) shall rank pari passu in right of payment with the Revolving Loans, (b) shall not mature earlier than the Maturity Date (but may have amortization prior to such date) and (c) shall be treated substantially the same as (and in any event no more favorably than) the Revolving Loans; provided that (i) the terms and conditions applicable to any tranche of Incremental Term Loans maturing after the Maturity Date may provide for material additional or different financial or other covenants or prepayment requirements applicable only during periods after the Maturity Date and (ii) the Incremental Term Loans may be priced differently than the Revolving Loans. Incremental Term Loans may be made hereunder pursuant to an amendment or restatement (an "Incremental Term Loan Amendment") of this Agreement and, as appropriate, the other Loan Documents, executed by the Borrower, each Increasing Lender participating in such tranche, each Augmenting Lender participating in such tranche, if any, and the Administrative Agent. The Incremental Term Loan Amendment may, without the consent of any other Lenders, effect such amendments to this Agreement and the other Loan Documents as may be necessary or appropriate, in the reasonable opinion of the Administrative Agent, to effect the provisions of this Section 2.20. Nothing contained in this Section 2.20 shall constitute, or otherwise be deemed to be, a commitment on the part of any Lender to increase its Commitment hereunder, or provide Incremental Term Loans, at any time. In connection with any increase of the Commitments or Incremental Term Loans pursuant to this Section 2.20, any Augmenting Lender becoming a party hereto shall (1) execute such documents and agreements as the Administrative Agent may reasonably request and (2) in the case of any Augmenting Lender that is organized under the laws of a jurisdiction outside of the United States of America, provide to the Administrative Agent, its name, address, tax identification number and/or such other information as shall be necessary for the Administrative Agent to comply with "know your customer" and anti-money laundering rules and regulations, including without limitation, the Patriot Act.

SECTION 2.21 Defaulting Lenders. Notwithstanding any provision of this Agreement to the contrary, if any Lender becomes a Defaulting Lender, then the following provisions shall apply for so long as such Lender is a Defaulting Lender:

(a) fees shall cease to accrue on the Commitment of such Defaulting Lender pursuant to Section 2.12(a);

(b) any payment of principal, interest, fees or other amounts received by the Administrative Agent for the account of such Defaulting Lender (whether voluntary or mandatory, at maturity, pursuant to Section 7.02 or otherwise) or received by the Administrative Agent from a Defaulting Lender pursuant to Section 9.08 shall be applied at such time or times as may be determined by the Administrative Agent as follows: *first*, to the payment of any amounts owing by such Defaulting Lender to the Administrative Agent hereunder; *second*, to the payment on a pro rata basis of any amounts owing by such Defaulting Lender to any Issuing Bank or Swingline Lender hereunder; *third*, to cash collateralize the LC Exposure with respect to such Defaulting Lender in accordance with this Section; *fourth*, as the Borrower may request (so long as no Default or Event of Default exists), to the funding of any Loan in respect of which such Defaulting Lender has failed to fund its portion thereof as required by this Agreement, as determined by the Administrative Agent; *fifth*, if so determined by the Administrative Agent and the Borrower, to be held in a deposit account and released pro rata in order to (x) satisfy such Defaulting Lender's potential future funding obligations with respect to Loans under this Agreement and (y) cash collateralize future LC Exposure with respect to such Defaulting Lender with respect to future

Letters of Credit issued under this Agreement, in accordance with this Section; *sixth*, to the payment of any amounts owing to the Lenders, the Issuing Banks or Swingline Lender as a result of any judgment of a court of competent jurisdiction obtained by any Lender, the Issuing Banks or Swingline Lender against such Defaulting Lender as a result of such Defaulting Lender's breach of its obligations under this Agreement or under any other Loan Document; *seventh*, so long as no Default or Event of Default exists, to the payment of any amounts owing to the Borrower as a result of any judgment of a court of competent jurisdiction obtained by the Borrower against such Defaulting Lender as a result of such Defaulting Lender's breach of its obligations under this Agreement or under any other Loan Document; and *eighth*, to such Defaulting Lender or as otherwise directed by a court of competent jurisdiction; provided that if (x) such payment is a payment of the principal amount of any Loans or LC Disbursements in respect of which such Defaulting Lender has not fully funded its appropriate share, and (y) such Loans were made or the related Letters of Credit were issued at a time when the conditions set forth in Section 4.02 were satisfied or waived, such payment shall be applied solely to pay the Loans of, and LC Disbursements owed to, all non-Defaulting Lenders on a pro rata basis prior to being applied to the payment of any Loans of, or LC Disbursements owed to, such Defaulting Lender until such time as all Loans and funded and unfunded participations in the Borrower's obligations corresponding to such Defaulting Lender's LC Exposure and Swingline Loans are held by the Lenders pro rata in accordance with the Commitments without giving effect to clause (d) below. Any payments, prepayments or other amounts paid or payable to a Defaulting Lender that are applied (or held) to pay amounts owed by a Defaulting Lender or to post cash collateral pursuant to this Section shall be deemed paid to and redirected by such Defaulting Lender, and each Lender irrevocably consents hereto;

(c) the Commitment and Revolving Credit Exposure of such Defaulting Lender shall not be included in determining whether the Required Lenders have taken or may take any action hereunder (including any consent to any amendment, waiver or other modification pursuant to Section 9.02); provided, that, except as otherwise provided in Section 9.02, this clause (c) shall not apply to the vote of a Defaulting Lender in the case of an amendment, waiver or other modification requiring the consent of such Lender or each Lender directly affected thereby;

(d) if any Swingline Exposure or LC Exposure exists at the time such Lender becomes a Defaulting Lender then:

(i) all or any part of the Swingline Exposure and LC Exposure of such Defaulting Lender (other than the portion of such Swingline Exposure referred to in clause (b) of the definition of such term) shall be reallocated among the non-Defaulting Lenders in accordance with their respective Applicable Percentages but only to the extent that such reallocation does not, as to any non-Defaulting Lender, cause such non-Defaulting Lender's Revolving Credit Exposure to exceed its Commitment;

(ii) if the reallocation described in clause (i) above cannot, or can only partially, be effected, the Borrower shall within three (3) Business Days following notice by the Administrative Agent (x) first, prepay such Swingline Exposure and (y) second, cash collateralize for the benefit of the applicable Issuing Banks only the Borrower's obligations corresponding to such Defaulting Lender's LC Exposure (after giving effect to any partial reallocation pursuant to clause (i) above) in accordance with the procedures set forth in Section 2.06(j) for so long as such LC Exposure is outstanding;

(iii) if the Borrower cash collateralizes any portion of such Defaulting Lender's LC Exposure pursuant to clause (ii) above, the Borrower shall not be required to pay any fees to such Defaulting Lender pursuant to Section 2.12(b) with respect to such Defaulting Lender's LC Exposure during the period such Defaulting Lender's LC Exposure is cash collateralized;

(iv) if the LC Exposure of the non-Defaulting Lenders is reallocated pursuant to clause (i) above, then the fees payable to the Lenders pursuant to Section 2.12(b) shall be adjusted in accordance with such non-Defaulting Lenders' Applicable Percentages; and

(v) if all or any portion of such Defaulting Lender's LC Exposure is neither reallocated nor cash collateralized pursuant to clause (i) or (ii) above, then, without prejudice to any rights or remedies of any Issuing Bank or any other Lender hereunder, all facility fees that otherwise would have been payable to such Defaulting Lender (solely with respect to the portion of such Defaulting Lender's Commitment that was utilized by such LC Exposure) and letter of credit fees payable under Section 2.12(b) with respect to such Defaulting Lender's LC Exposure shall be payable to the Issuing Banks until and to the extent that such LC Exposure is reallocated and/or cash collateralized; and

(e) so long as such Lender is a Defaulting Lender, the Swingline Lender shall not be required to fund any Swingline Loan and no Issuing Bank shall be required to issue, amend or increase any Letter of Credit, unless it is satisfied that the related exposure and the Defaulting Lender's then outstanding LC Exposure will be 100% covered by the Commitments of the non-Defaulting Lenders and/or cash collateral will be provided by the Borrower in accordance with Section 2.21(d), and Swingline Exposure related to any newly made Swingline Loan or LC Exposure related to any newly issued or increased Letter of Credit shall be allocated among non-Defaulting Lenders in a manner consistent with Section 2.21(d)(i) (and such Defaulting Lender shall not participate therein).

If (i) a Bankruptcy Event or a Bail-In Action with respect to a Lender Parent shall occur following the date hereof and for so long as such event shall continue or (ii) any Swingline Lender or Issuing Bank has a good faith belief that any Lender has defaulted in fulfilling its obligations under one or more other agreements in which such Lender commits to extend credit, the Swingline Lender shall not be required to fund any Swingline Loan and no Issuing Bank shall be required to issue, amend or increase any Letter of Credit, unless the Swingline Lender or the Issuing Banks, as the case may be, shall have entered into arrangements with the Borrower or such Lender, satisfactory to the Swingline Lender or such Issuing Bank, as the case may be, to defease any risk to it in respect of such Lender hereunder.

In the event that the Administrative Agent, the Borrower, the Swingline Lender and each Issuing Bank agrees that a Defaulting Lender has adequately remedied all matters that caused such Lender to be a Defaulting Lender, then the Swingline Exposure and LC Exposure of the Lenders shall be readjusted to reflect the inclusion of such Lender's Commitment and on such date such Lender shall purchase at par such of the Loans of the other Lenders (other than Swingline Loans) as the Administrative Agent shall determine may be necessary in order for such Lender to hold such Loans in accordance with its Applicable Percentage.

SECTION 2.22 Extension of Maturity Date.

(a) The Borrower may, by delivering an Extension Request to the Administrative Agent (who shall promptly deliver a copy to each of the Lenders), not less than 60 days in advance of the Maturity Date in effect at such time (the "Existing Maturity Date"), request that the Lenders extend the Existing Maturity Date to the first anniversary of such Existing Maturity Date (or, if such date is not a Business Day, the immediately preceding Business Day). Each Lender, acting in its sole discretion, shall, by written notice to the Administrative Agent given not later than the date that is the 20th day after the date of the Extension Request, or if such date is not a Business Day, the immediately following Business Day (the "Response Date"), advise the Administrative Agent in writing whether or not such Lender agrees to the requested extension. Each Lender that advises the Administrative Agent that it will not extend the Existing Maturity Date is referred to herein as a "Non-extending Lender"; provided, that any Lender that does not advise the Administrative Agent of its consent to such requested extension by the Response Date and any Lender that is a Defaulting Lender on the Response Date shall be deemed to be a Non-extending Lender. The Administrative Agent shall notify the Borrower, in writing, of the Lenders' elections promptly following the Response Date. The election of any Lender to agree to such an extension shall not obligate any other Lender to so agree, and it is understood that no Lender shall have any obligation whatsoever to agree to any request made by the Borrower for an extension of the Existing Maturity Date. The Maturity Date may be extended no more than two times pursuant to this Section 2.22.

(b) (i) If, by the Response Date, Lenders holding Commitments that aggregate 50% or more of the Aggregate Commitment shall constitute Non-extending Lenders, then the Existing Maturity Date shall not be extended and the outstanding principal balance of all Loans and other amounts payable hereunder shall be payable, and the Commitments shall terminate, on the Existing Maturity Date in effect prior to such extension.

(ii) If (and only if), by the Response Date, Lenders holding Commitments that aggregate more than 50% of the Aggregate Commitment shall have agreed to extend the Existing Maturity Date (each such consenting Lender, an "Extending Lender"), then effective as of the Existing Maturity Date, the Maturity Date for such Extending Lenders shall be extended to the first anniversary of the Existing Maturity Date (subject to satisfaction of the conditions set forth in Section 2.22(d)). In the event of such extension, the Commitment of each Non-extending Lender shall terminate on the Existing Maturity Date in effect for such Non-extending Lender prior to such extension and the outstanding principal balance of all Loans and other amounts payable hereunder to such Non-extending Lender shall become due and payable on such Existing Maturity Date and, subject to Section 2.22(c) below, the Aggregate Commitment hereunder shall be reduced by the Commitments of the Non-extending Lenders so terminated on such Existing Maturity Date. For purposes of clarity, it is acknowledged and agreed that the Maturity Date on any date of determination shall not be a date more than five (5) years after such date of determination, whether such determination is made before or after giving effect to any extension request made hereunder.

(c) In the event of any extension of the Existing Maturity Date pursuant to Section 2.22(b)(ii), the Borrower shall have the right on or before the Existing Maturity Date, at its own expense, to require any Non-extending Lender to transfer and assign without recourse (in accordance with and subject to the restrictions contained in Section 9.04) all its interests, rights (other than its rights to payments pursuant to Section 2.15, Section 2.16, Section 2.17 or Section 9.03 arising prior to the effectiveness of such assignment) and obligations under this Agreement to one or more banks or other financial institutions identified to the Non-extending Lender by the Borrower, which may include any existing Lender (each a "Replacement Lender"), provided that (i) such Replacement Lender, if not already a Lender hereunder, shall be subject to the approval of the Administrative Agent, the Issuing Banks and the Swingline Lender (such approvals to not be unreasonably withheld) to the extent the consent of the Administrative Agent, the Issuing Banks or the Swingline Lender would be required to effect an assignment under Section 9.04(b), (ii) such assignment shall become effective as of a date specified by the Borrower (which shall not be later than the Existing Maturity Date in effect for such Non-extending Lender prior to the effective date of the requested extension) and (iii) the Replacement Lender shall pay to such Non-extending Lender in immediately available funds on the effective date of such assignment the principal of and interest accrued to the date of payment on the outstanding principal amount Loans made by it hereunder and all other amounts accrued and unpaid for its account or otherwise owed to it hereunder on such date.

(d) As a condition precedent to each such extension of the Existing Maturity Date pursuant to Section 2.22(b)(ii), the Borrower shall (i) deliver to the Administrative Agent a certificate of the Borrower dated as of the Existing Maturity Date signed by a Responsible Officer of the Borrower certifying that, as of such date, both before and immediately after giving effect to such extension, (A) the representations and warranties of the Borrower set forth in this Agreement shall be true and correct in all material respects, except for any representation or warranty that is qualified by materiality or reference to Material Adverse Effect, which representation and warranty shall be true and correct in all respects (except, in each case, to the extent that any such representation or warranty specifically refers to an earlier date, in which case it shall be true and correct in all material respects, or in all respects, as applicable, as of such earlier date) and (B) no Default shall have occurred and be continuing, (ii) the Administrative Agent shall have received all fees and other amounts due and payable on or prior to such extension of the Existing Maturity Date, including, to the extent invoiced, reimbursement or payment of all out-of-pocket expenses required to be reimbursed or paid by the Borrower and (iii) first make such prepayments of the outstanding Loans and second provide such cash collateral (or make such other arrangements satisfactory to the applicable Issuing Bank) with respect to the outstanding Letters of Credit as shall be required such that, after giving effect to the termination of the Commitments of the Non-extending Lenders pursuant to Section 2.22(b) and any assignment pursuant to Section 2.22(c), the aggregate Revolving Credit Exposure less the face amount of any Letter of Credit supported by any such cash collateral (or other satisfactory arrangements) so provided does not exceed the aggregate amount of Commitments being extended.

(e) For the avoidance of doubt, no consent of any Lender (other than the existing Lenders participating in the extension of the Existing Maturity Date) shall be required for any extension of the Maturity Date pursuant to this Section 2.22 and the operation of this Section 2.22 in accordance with its terms is not an amendment subject to Section 9.02.

ARTICLE III

Representations and Warranties

The Borrower represents and warrants to the Lenders that:

SECTION 3.01 Corporate Existence; Authorization. The Borrower (a) has been duly incorporated and is validly existing as a corporation under the laws of its jurisdiction of incorporation, (b) has the requisite corporate power and authority to consummate the Transactions and (c) has duly taken all necessary corporate action to authorize the Transactions.

SECTION 3.02 Enforceability. This Agreement and each note delivered hereunder has been duly executed and delivered by the Borrower is the legal, valid and binding obligation of the Borrower, enforceable against it in accordance with its terms, and any other instrument or agreement required hereunder, when executed and delivered, will be similarly valid, binding and enforceable, except (in each case) to the extent that the enforcement thereof may be limited by bankruptcy, insolvency, reorganization or similar laws generally affecting creditors' rights and by general principles of equity.

SECTION 3.03 Financial Condition; No Material Adverse Change. (a) All fiscal year-end financial statements furnished by the Borrower to the Administrative Agent or any Lender have been prepared in accordance with GAAP consistently applied, except as noted therein, and fairly present the consolidated financial position and the consolidated results of operations of the Borrower as of the dates and for the periods presented. Financial statements and other information and data furnished to the Administrative Agent or any Lender other than fiscal year-end statements of the Borrower are in reasonable detail and present fairly the consolidated financial position and consolidated results of operations of the Borrower as of the dates and for the periods presented, subject to year-end audit adjustments.

(b) As of the Restatement Effective Date, there has been no material adverse change in the business or financial condition of the Borrower and its Subsidiaries, taken as a whole, except as disclosed in the Borrower's periodic reports filed with the SEC under the Securities Exchange Act of 1934 on or before the Restatement Effective Date.

SECTION 3.04 Compliance with Laws and Material Contractual Obligations. The operations of the Borrower and its Significant Subsidiaries are in compliance with (a) all Requirements of Law and (b) its obligations under material agreements to which it is a party, (i) except to the extent that the failure to comply therewith could not, in the aggregate, be reasonably expected to have a Material Adverse Effect or (ii) except as disclosed in the Borrower's periodic reports filed prior to the date of this Agreement with the SEC under the Securities Exchange Act of 1934. Neither the execution and delivery of this Agreement, nor the consummation of the transactions herein contemplated, will violate (x) any Requirement of Law, (y) violate or result in a default under any indenture or other material agreement or other material instrument binding upon the Borrower or any of its Subsidiaries or its assets, or give rise to a right thereunder to require any material payment to be made by the Borrower or any of its Subsidiaries or (z) result in the creation or imposition of, or the requirement to create, any lien or security interest on any asset of the Borrower or any of its Subsidiaries.

SECTION 3.05 No Material Litigation. No litigation, investigation or proceeding of or before any arbitrator or Governmental Authority is pending or, to the knowledge of the Borrower, threatened by or against the Borrower or any of its Subsidiaries or against any of its or their respective properties or revenues (a) with respect to this Agreement or any of the transactions contemplated hereby or (b) which could, insofar as the Borrower may reasonably foresee, have a Material Adverse Effect, except as disclosed in the Borrower's periodic reports filed with the SEC prior to the date of this Agreement under the Securities Exchange Act of 1934.

SECTION 3.06 Ownership of Property. Each of the Borrower and each of its Significant Subsidiaries has title in fee simple to or valid leasehold interests in all its real property material to the operation of its business, and title to or valid leasehold interests in all its other property useful and necessary in its business.

SECTION 3.07 Taxes. Each of the Borrower and each of its Significant Subsidiaries has filed or caused to be filed all Tax returns which to the knowledge of the Borrower are required to be filed and has paid all material taxes shown to be due and payable on said returns or on any assessments made against it or any of its property and all other material Taxes, fees or other charges imposed on it or any of its property by any Governmental Authority (other than those the amount or validity of which is currently being contested in good faith by appropriate proceedings and with respect to which reserves in conformity with GAAP have been provided on the books of the Borrower or the applicable Subsidiary, as the case may be); and no material Tax liens have been filed and, to the knowledge of the Borrower, no material claims are being asserted with respect to any such Taxes, fees or other charges.

SECTION 3.08 Subsidiaries. Schedule 3.08 contains an accurate list of all of the Subsidiaries of the Borrower existing as of the Restatement Effective Date, setting forth their respective jurisdictions of incorporation and the percentage of their respective Equity Interests owned by the Borrower and/or other Subsidiaries. All of the issued and outstanding shares of Equity Interests of such Subsidiaries have been duly authorized and issued and are fully paid and nonassessable.

SECTION 3.09 Investment Company Act; No Consents. Neither the Borrower nor any Subsidiary is an “Investment Company”, as defined in, or subject to regulation under, the Investment Company Act of 1940, as amended. Except for the Required Filings and orders of the Commissions in respect thereof, no authorizations, approvals or consents of, no filings or registrations with, any Governmental Authority are necessary for the consummation of the Transactions or for the validity or enforceability hereof or the notes delivered hereunder.

SECTION 3.10 ERISA. The Borrower is in compliance in all material respects with all applicable provisions of ERISA. The Borrower has not violated any provision of any Plan maintained or contributed to by the Borrower which could, insofar as the Borrower may reasonably foresee, have a Material Adverse Effect. No Reportable Event has occurred and is continuing with respect to any Plan initiated by the Borrower (other than the Borrower’s December 22, 2013 withdrawal from the Western States Office and Professional Employees International Union Pension Fund). The Borrower has met its minimum funding requirements under ERISA with respect to each Plan. Each Plan will be able to fulfill its benefit obligations as they come due in accordance with the Plan documents and under GAAP.

SECTION 3.11 Environmental. In the ordinary course of its business, the Borrower conducts an ongoing review of the effect of Environmental Laws on the business, operations, and properties of the Borrower, in the course of which it identifies and evaluates associated liabilities and costs (including any capital or operating expenditures required for clean-up or closure of properties presently or previously owned or operated, any capital or operating expenditures required to achieve or maintain compliance with environmental protection standards imposed by law or as a condition of any license, permit or contract, any related constraints on operating activities, including any periodic or permanent shutdown of any facility or reduction in the level of or change in the nature of operations conducted thereat and any actual or potential liabilities to third parties, including employees, and any related costs and expenses). On the basis of these reviews, the Borrower has reasonably concluded that Environmental Laws are unlikely to have a Material Adverse Effect. The Borrower hereby represents and warrants that its business and assets and those of its Subsidiaries are operated, and covenants that its and its Subsidiaries’ business and assets will continue to be operated, in compliance with applicable Environmental Laws and that no enforcement action in respect thereof is threatened or pending that could, in the case of any failure to so comply or any such enforcement action, insofar as the Borrower may reasonably foresee, have a Material Adverse Effect, except as disclosed in the Borrower’s periodic reports filed with the SEC on or prior to the date of this Agreement under the Securities Exchange Act of 1934.

SECTION 3.12 Margin Regulations. The Borrower is not engaged and will not engage, principally or as one of its important activities, in the business of purchasing or carrying Margin Stock, or extending credit for the purpose of purchasing or carrying Margin Stock, and no part of the proceeds of any Borrowing or Letter of Credit extension hereunder will be used to buy or carry any Margin Stock. Following the application of the proceeds of each Borrowing or drawing under each Letter of Credit, not more than 25% of the value of the assets (either of the Borrower only or of the Borrower and its Subsidiaries on a consolidated basis) will be Margin Stock.

SECTION 3.13 Disclosure. (a) As of the Restatement Effective Date, neither the Information Memorandum nor any of the other reports, financial statements, certificates or other information furnished by or on behalf of the Borrower or any Subsidiary to the Administrative Agent or any Lender in connection with the negotiation of this Agreement or delivered hereunder (as modified or supplemented by other information so furnished) contains any material misstatement of fact or omits to state any material fact necessary to make the statements therein, in the light of the circumstances under which they were made, not misleading; provided that, with respect to projected financial information, the Borrower represents only that such information was prepared in good faith based upon assumptions believed to be reasonable at the time.

(b) As of the Restatement Effective Date, to the best knowledge of the Borrower, the information included in the Beneficial Ownership Certification provided on or prior to the Restatement Effective Date to any Lender in connection with this Agreement is true and correct in all respects.

SECTION 3.14 Anti-Corruption Laws and Sanctions. The Borrower has implemented and maintains in effect policies and procedures designed to ensure compliance by the Borrower, its Subsidiaries and their respective directors, officers, employees and agents with Anti-Corruption Laws and applicable Sanctions, and the Borrower, its Subsidiaries and their respective officers and directors and to the knowledge of the Borrower its employees and agents, are in compliance with Anti-Corruption Laws and applicable Sanctions in all material respects. None of (a) the Borrower, any Subsidiary, any of their respective directors or officers, or employees, or (b) to the knowledge of the Borrower, any agent of the Borrower or any Subsidiary that will act in any capacity in connection with or benefit from the credit facility established hereby, is a Sanctioned Person. No Borrowing or Letter of Credit, use of proceeds or other Transactions will violate any Anti-Corruption Law or applicable Sanctions.

SECTION 3.15 Affected Financial Institutions. The Borrower is not an Affected Financial Institution.

SECTION 3.16 Plan Assets; Prohibited Transactions. None of the Borrower or any of its Subsidiaries is an entity deemed to hold “plan assets” (within the meaning of the Plan Asset Regulations), and neither the execution, delivery or performance of the Transactions, including the making of any Loan and the issuance of any Letter of Credit hereunder, will give rise to a non-exempt prohibited transaction under Section 406 of ERISA or Section 4975 of the Code.

ARTICLE IV

Conditions

SECTION 4.01 Restatement Effective Date. The obligations of the Lenders to make Loans and of the Issuing Banks to issue Letters of Credit hereunder shall not become effective until the date on which each of the following conditions is satisfied (or waived in accordance with Section 9.02):

(a) The Administrative Agent (or its counsel) shall have received (i) from each party hereto either (A) a counterpart of this Agreement signed on behalf of such party or (B) written evidence satisfactory to the Administrative Agent (which may include telecopy or electronic transmission of a signed signature page of this Agreement) that such party has signed a counterpart of this Agreement and (ii) duly executed copies of the Loan Documents and such other legal opinions, certificates, documents, instruments and agreements as the Administrative Agent shall reasonably request in connection with the Transactions, all in form and substance satisfactory to the Administrative Agent and its counsel and as further described in the list of closing documents attached as Exhibit D.

(b) The Administrative Agent shall have received a favorable written opinion (addressed to the Administrative Agent and the Lenders and dated the Restatement Effective Date) of

Stoel Rives LLP, counsel for the Borrower, covering such matters relating to the Borrower, the Loan Documents or the Transactions as the Administrative Agent shall reasonably request. The Borrower hereby requests such counsel to deliver such opinion.

(c) The Administrative Agent shall have received such documents and certificates as the Administrative Agent or its counsel may reasonably request relating to the organization and valid existence of the Borrower, the authorization of the Transactions and any other legal matters relating to the Borrower, the Loan Documents or the Transactions, all in form and substance satisfactory to the Administrative Agent and its counsel and as further described in the list of closing documents attached as Exhibit D.

(d) The Administrative Agent shall have received a certificate, dated the Restatement Effective Date and signed by a Responsible Officer of the Borrower, certifying (i) that the representations and warranties contained in Article III are true and correct as of such date and (ii) that no Default or Event of Default has occurred and is continuing as of such date.

(e) The Administrative Agent shall have received, for the account of the applicable Persons, payment of (x) all accrued and unpaid interest and fees owing under the Existing Credit Agreement immediately prior to the Restatement Effective Date and (y) all principal of any "Swingline Loans" outstanding under and as defined in the Existing Credit Agreement immediately prior to the Restatement Effective Date.

(f) The Administrative Agent shall have received all fees and other amounts due and payable on or prior to the Restatement Effective Date, including, to the extent invoiced, reimbursement or payment of all out-of-pocket expenses required to be reimbursed or paid by the Borrower hereunder.

(g) The Administrative Agent shall have received (i) satisfactory audited consolidated financial statements of the Borrower for the two most recent fiscal years ended prior to the Restatement Effective Date as to which such financial statements are available and (ii) satisfactory unaudited interim consolidated financial statements of the Borrower for each quarterly period ended subsequent to the date of the latest financial statements delivered pursuant to clause (i) as to which such financial statements are available.

(h) (i) The Administrative Agent shall have received, at least five days prior to the Restatement Effective Date (or such shorter period agreed to by the Administrative Agent in its sole discretion), all documentation and other information regarding the Borrower requested in connection with applicable "know your customer" and anti-money laundering rules and regulations, including the Patriot Act, to the extent requested in writing of the Borrower at least 10 days prior to the Restatement Effective Date and (ii) to the extent the Borrower qualifies as a "legal entity customer" under the Beneficial Ownership Regulation, at least five days prior to the Restatement Effective Date, any Lender that has requested, in a written notice to the Borrower at least 10 days prior to the Restatement Effective Date, a Beneficial Ownership Certification in relation to the Borrower shall have received such Beneficial Ownership Certification (provided that, upon the execution and delivery by such Lender of its signature page to this Agreement, the condition set forth in this clause (ii) shall be deemed to be satisfied).

(i) The Administrative Agent shall have received such other documents as the Administrative Agent or the Required Lenders (through the Administrative Agent) may reasonably request.

The Administrative Agent shall notify the Borrower and the Lenders of the Restatement Effective Date, and such notice shall be conclusive and binding. Notwithstanding the foregoing, the obligations of the Lenders to make Loans and of the Issuing Banks to issue Letters of Credit hereunder shall not become effective unless each of the foregoing conditions is satisfied (or waived pursuant to Section 9.02) at or prior to 3:00 p.m., New York City time, on November 3, 2021 (and, in the event such conditions are not so satisfied or waived, the Commitments shall terminate at such time).

SECTION 4.02 Each Credit Event. The obligation of each Lender to make a Loan on the occasion of any Borrowing, and of the Issuing Banks to issue, amend, renew or extend any Letter of Credit, is subject to the satisfaction of the following conditions:

(a) The representations and warranties of the Borrower set forth in this Agreement (other than, except in the case of the initial Loans, the representations and warranties set forth in Sections 3.04(b), 3.05(b) and 3.11) shall be true and correct in all material respects, except for any such representation or warranty that is qualified by materiality or reference to Material Adverse Effect, which representation and warranty shall be true and correct in all respects, on and as of the date of such Borrowing or the date of issuance, amendment, renewal or extension of such Letter of Credit (except, in each case, to the extent that any such representation or warranty specifically refers to an earlier date, in which case it shall be true and correct in all material respects, or in all respects, as applicable, as of such earlier date), as applicable.

(b) At the time of and immediately after giving effect to such Borrowing or the issuance, amendment, renewal or extension of such Letter of Credit, as applicable, no Default or Event of Default shall have occurred and be continuing.

Each Borrowing and each issuance, amendment, renewal or extension of a Letter of Credit shall be deemed to constitute a representation and warranty by the Borrower on the date thereof as to the matters specified in paragraphs (a) and (b) of this Section.

ARTICLE V

Affirmative Covenants

Until the Commitments have expired or been terminated and the principal of and interest on each Loan and all fees payable hereunder shall have been paid in full and all Letters of Credit shall have expired or terminated, in each case, without any pending draw, and all LC Disbursements shall have been reimbursed, the Borrower covenants and agrees with the Lenders that:

SECTION 5.01 Financial Statements and Other Information. The Borrower will furnish to the Administrative Agent and each Lender:

(a) as soon as practicable, but in any event within 120 days after the end of each fiscal year of the Borrower (commencing with the fiscal year ending December 31, 2021), a copy of the consolidated balance sheet of the Borrower and its audited consolidated Subsidiaries as at the end of such year and the related consolidated statements of income, of shareholders' equity and comprehensive income and of cash flows for such year, setting forth in each case in comparative form the figures for the previous year, audited by independent certified public accountants of nationally recognized standing (without any qualification or exception as to the scope of such audit) to the effect that such consolidated financial statements present fairly in all material respects the financial condition and results of operations of the Borrower and its consolidated Subsidiaries on a consolidated basis in accordance with GAAP consistently applied;

(b) as soon as practicable, but in any event not later than 60 days after the end of each of the first three quarterly periods of each fiscal year of the Borrower (commencing with the fiscal quarter ending September 30, 2021), the Form 10-Q as filed by the Borrower with the SEC for each such fiscal quarter, certified by an Authorized Officer as being complete and correct (subject to normal year-end audit adjustments); and

(c) together with the financial statements required hereunder, a compliance certificate in form and substance satisfactory to the Administrative Agent signed by its chief financial officer or chief accounting officer showing the calculations necessary to determine compliance with this Agreement, including its calculation of maintenance of Consolidated Indebtedness to Total Capitalization, and stating that no Default exists, or if any Default exists, stating the nature and status thereof.

All such financial statements shall be prepared in reasonable detail and in accordance with GAAP applied consistently throughout the periods reflected therein (except as approved by such accountants or officer, as the case may be, and disclosed therein).

SECTION 5.02 Certificates; Other Information. The Borrower shall furnish to the Administrative Agent and each Lender as soon as practicable, but in any event within ten days after the same are sent, copies of all financial statements and reports which the Borrower or Holdings sends to its shareholders, and within ten days after the same are filed, copies of all financial statements and reports which the Borrower or Holdings may make to, or file with, the SEC or any successor or analogous Governmental Authority. Promptly following any request therefor, the Borrower shall furnish (x) such other information regarding the operations, business affairs and financial condition of the Borrower or any Subsidiary, or compliance with the terms of this Agreement, as the Administrative Agent or any Lender may reasonably request, (y) information and documentation reasonably requested by the Administrative Agent or any Lender for purposes of compliance with applicable "know your customer" and anti-money laundering rules and regulations, including the Patriot Act and the Beneficial Ownership Regulation, and (z) any information regarding sustainability matters and practices of the Borrower and its Subsidiaries (including with respect to corporate governance, environmental, social and employee matters, respect for human rights, anti-corruption and anti-bribery) as the Administrative Agent or any Lender may reasonably request for purposes of compliance with any legal or regulatory requirement applicable to the Administrative Agent or any such Lender; and the Borrower shall furnish to the Administrative Agent and each Lender prompt written notice of any change in the information provided in the Beneficial Ownership Certification delivered to such Lender that would result in a change to the list of beneficial owners identified in such certification. The Borrower hereby acknowledges that (a) the Administrative Agent and/or the Arrangers will make available to the Lenders and the Issuing Banks materials and/or information provided by or on behalf of the Borrower hereunder (collectively, "Borrower Materials") by posting the Borrower Materials on IntraLinks or another similar electronic system (the "Platform") and (b) certain of the Lenders may be "public-side" Lenders (*i.e.,* Lenders that do not wish to receive material non-public information with respect to the Borrower or its securities) (each, a "Public Lender"). The Borrower hereby agrees that (w) all Borrower Materials that are to be made available to Public Lenders shall be clearly and conspicuously marked "PUBLIC" which, at a minimum, shall mean that the word "PUBLIC" shall appear prominently on the first page thereof; (x) by marking Borrower Materials "PUBLIC," the Borrower shall be deemed to have authorized the Administrative Agent, the Arrangers, the Issuing Banks and the Lenders to treat such Borrower Materials as either publicly available information or not material information (although it may be sensitive and proprietary) with respect to the Borrower or its securities for purposes of United States Federal and state securities laws; (y) all Borrower Materials marked "PUBLIC" are permitted to be made available through a portion of the Platform designated "Public Investor;" and (z) the Administrative Agent and the Arrangers shall be entitled to treat any Borrower Materials that are not marked "PUBLIC" as being suitable only for posting on a portion of the Platform not designated "Public Investor."

SECTION 5.03 Payment of Taxes. The Borrower shall, and shall cause each of its Subsidiaries to, pay, discharge or otherwise satisfy at or before maturity or before they become delinquent, as the case may be, all taxes, except when (a) the amount or validity thereof is currently being contested in good faith by appropriate proceedings or (b) reserves in conformity with GAAP with respect thereto have been provided on the books of the Borrower or such Subsidiary, as the case may be.

SECTION 5.04 Conduct of Business. The Borrower shall (a) carry on and conduct its business in substantially the same manner and in substantially the same fields of enterprise as it is presently conducted and to do all things necessary to remain duly incorporated, validly existing and in good standing as a domestic corporation in its jurisdiction of incorporation and maintain all requisite authority to conduct its business in each jurisdiction in which its business is conducted, and (b) comply with all Requirements of Law, except to the extent that failure to comply therewith could not, in the aggregate, have a Material Adverse Effect. The Borrower will maintain in effect and enforce policies and procedures designed to ensure compliance by the Borrower, its Subsidiaries and their respective directors, officers, employees and agents with Anti-Corruption Laws and applicable Sanctions.

SECTION 5.05 Maintenance of Property; Insurance. The Borrower shall, and shall cause each of its Subsidiaries to, (a) keep all property useful and necessary in its business in good working order and condition; (b) maintain with financially sound and reputable insurance companies insurance on such property in at least such amounts and against at least such risks as are usually insured against in the same general area by companies engaged in the same or a similar business; and (c) furnish to the Administrative Agent or any Lender, upon written request, full information as to the insurance carried.

SECTION 5.06 Inspection of Property; Books and Records; Discussions. The Borrower shall, and shall cause each of its Subsidiaries that have business operations to, (a) keep proper books of records and accounts in which entries in conformity with GAAP shall be made of all dealings and transactions in relation to its business and activities and (b) permit representatives of the Administrative Agent or any Lender, at such Person's expense, to visit and inspect any of its properties and examine and make abstracts from any of its books and records upon reasonable notice and during regular working hours, and to discuss the business, operations, properties and financial and other condition of the Borrower and its Subsidiaries with officers and employees of the Borrower and its Subsidiaries.

SECTION 5.07 Notices. The Borrower shall promptly give notice to the Administrative Agent and each Lender of (a) the occurrence of any Default; (b) any litigation, investigation or proceeding involving the Borrower or any of its Subsidiaries which, if not cured or if adversely determined, as the case may be, would have a Material Adverse Effect; (c) any change in any Debt Rating and (d) any Pricing Certificate Inaccuracy. Each notice pursuant to this Section 5.07 shall be accompanied by a statement of an Authorized Officer setting forth details of the occurrence referred to therein and stating what action the Borrower proposes to take with respect thereto.

SECTION 5.08 Use of Proceeds and Letters of Credit. The proceeds of the Loans will be used only to finance the working capital needs, and for general corporate purposes, of the Borrower and its Subsidiaries (other than Hostile Acquisitions). No part of the proceeds of any Loan will be used, whether directly or indirectly, for any purpose that entails a violation of any of the regulations of the Federal Reserve Board, including Regulations T, U and X. Letters of Credit will be issued only to support the Borrower and its Subsidiaries. The Borrower will not request any Borrowing or Letter of Credit, and the Borrower shall not use, and shall procure that its Subsidiaries and its or their respective directors, officers, employees and agents shall not use, the proceeds of any Borrowing or Letter of Credit (i) in furtherance of an offer, payment, promise to pay, or authorization of the payment or giving of money, or anything else of value, to any Person in violation of any Anti-Corruption Laws, (ii) for the purpose of funding, financing or facilitating any activities, business or transaction of or with any Sanctioned Person, or in any Sanctioned Country, except to the extent permitted for a Person required to comply with Sanctions, or (iii) in any manner that would result in the violation of any Sanctions applicable to any party hereto.

SECTION 5.09 Debt Rating. The Borrower shall maintain at all times a Debt Rating from both Moody's and S&P.

ARTICLE VI

Negative Covenants

Until the Commitments have expired or terminated and the principal of and interest on each Loan and all fees payable hereunder have been paid in full and all Letters of Credit have expired or terminated, in each case, without any pending draw, and all LC Disbursements shall have been reimbursed, the Borrower covenants and agrees with the Lenders that it will not:

SECTION 6.01 Fundamental Changes. With respect to the Borrower or any Significant Subsidiary, without the consent of the Administrative Agent and the Required Lenders enter into any transaction of merger or consolidation or amalgamation, or liquidate, wind up or dissolve (or suffer any liquidation or dissolution), convey, sell, lease, transfer or otherwise dispose of, in one transaction or a series of transactions, all or substantially all of the consolidated assets of the Borrower and its Subsidiaries, taken as a whole, except (a) for sales, leases or rentals of property or assets in the ordinary course of business, (b) that any consolidated Subsidiary of the Borrower may be merged or consolidated with or into the Borrower (provided that the Borrower shall be the continuing or surviving corporation) or with any one or more Subsidiaries of the Borrower (provided that if any such transaction shall be between a Subsidiary and a wholly-owned Subsidiary, the wholly-owned Subsidiary shall be the continuing or surviving corporation), (c) any Subsidiary may sell, lease, transfer or otherwise dispose of any or all of its assets (upon voluntary liquidation or otherwise) to the Borrower or another wholly-owned Subsidiary of the Borrower and (d) the Borrower may be merged with any other Person if (i) the Borrower is the surviving corporation, (ii) immediately after giving effect to such merger, there shall exist no condition or event which constitutes an Event of Default or which, with the giving of notice or lapse of time or both, would constitute an Event of Default, and (iii) all representations and warranties contained in Article III hereof are true and correct in all material respects (except for any such representation and warranty that is qualified by materiality or reference to Material Adverse Effect, which representation shall be true and correct in all respects) on and as of the date of the consummation of such merger, and after giving effect thereto, as though restated on and as of such date (except to the extent that such representations and warranties specifically refer to an earlier date, in which case they shall be true and correct in all material respects (except for any such representation and warranty that is qualified by materiality or reference to Material Adverse Effect, which representation shall be true and correct in all respects) as of such earlier date).

SECTION 6.02 Financial Covenant. Maintenance of Consolidated Indebtedness to Total Capitalization. As at the end of any fiscal quarter of the Borrower, permit Consolidated Indebtedness to be greater than 70% of Total Capitalization.

ARTICLE VII

Events of Default

SECTION 7.01 Events of Default. If any of the following events ("Events of Default") shall occur:

(a) The Borrower shall fail to pay any principal of the Loans when due in accordance with the terms hereof; or

(b) The Borrower shall fail to pay any interest on the Loans, or any other amount payable by the Borrower hereunder, within five days after any such amount becomes due in accordance with the terms hereof; or

(c) Any representation or warranty made or deemed made by the Borrower herein shall prove to have been incorrect in any material respect on or as of the date made; or

(d) The Borrower shall default in the observance or performance of any covenant described in Sections 5.08, 6.01 or 6.02; or the Borrower shall default in the observance or performance of any other agreement or covenant contained in this Agreement, and such default shall continue unremedied for a period of 30 days after the earlier of (i) the date a Responsible Officer has knowledge of such default or (ii) written notice of such default shall have been given to the Borrower by the Administrative Agent or any Lender; or

(e) The Borrower shall fail to make any payment in respect of any Indebtedness having singly or in the aggregate an outstanding amount in excess of $50 million when due or within any applicable grace period; or

(f) A final judgment for the payment of money exceeding an aggregate of $15 million shall be rendered or entered against the Borrower and/or any Significant Subsidiary and the same shall remain undischarged for a period of 60 days during which execution shall not be effectively stayed or contested in good faith; or

(g) An involuntary proceeding shall be commenced or an involuntary petition shall be filed seeking (i) liquidation, reorganization or other relief in respect of the Borrower or any Significant Subsidiary or its debts, or of a substantial part of its assets, under any Federal, state or foreign bankruptcy, insolvency, receivership or similar law now or hereafter in effect or (ii) the appointment of a receiver, trustee, custodian, sequestrator, conservator or similar official for the Borrower or any Significant Subsidiary or for a substantial part of its assets, and, in any such case, such proceeding or petition shall continue undismissed for 60 days or an order or decree approving or ordering any of the foregoing shall be entered; or

(h) The Borrower or any Significant Subsidiary shall (i) voluntarily commence any proceeding or file any petition seeking liquidation, reorganization or other relief under any Federal, state or foreign bankruptcy, insolvency, receivership or similar law now or hereafter in effect, (ii) consent to the institution of, or fail to contest in a timely and appropriate manner, any proceeding or petition described in clause (g) above, (iii) apply for or consent to the appointment of a receiver, trustee, custodian, sequestrator, conservator or similar official for the Borrower or any Significant Subsidiary or for a substantial part of its assets, (iv) file an answer admitting the material allegations of a petition filed against it in any such proceeding, (v) make a general assignment for the benefit of creditors, (vi) become unable, admit in writing its inability or fail generally to pay its debts as they become due or (vii) take any action for the purpose of effecting any of the foregoing;

(i) a Change in Control shall occur;

(j) an ERISA Event shall have occurred (other than the Borrower's December 22, 2013 withdrawal from the Western States Office and Professional Employees International Union Pension Fund) that, in the opinion of the Required Lenders, when taken together with all other ERISA Events that have occurred, could reasonably be expected to result in a Material Adverse Effect; or

(k) any material provision of any Loan Document, at any time after its execution and delivery and for any reason other than as expressly permitted hereunder or thereunder or satisfaction in full of all Obligations, ceases to be in full force and effect; or the Borrower or any Subsidiary contests in writing the validity or enforceability of any provision of any Loan Document; or, prior to satisfaction in full of all Obligations, the Borrower denies in writing that it has any or further liability or obligation under any Loan Document, or the Borrower purports in writing to revoke, terminate or rescind any Loan Document other than in compliance with Section 9.02;

then, and in every such event (other than an event with respect to the Borrower, described in clause (g) or (h) above), and at any time thereafter during the continuance of such event, the Administrative Agent may, and at the request of the Required Lenders shall, by notice to the Borrower, take either or both of the following actions, at the same or different times: (i) terminate the Commitments, and thereupon the Commitments shall terminate immediately, and/or (ii) declare the Loans then outstanding to be due and payable in whole (or in part, in which case any principal not so declared to be due and payable may thereafter be declared to be due and payable), and thereupon the principal of the Loans so declared to be due and payable, together with accrued interest thereon and all fees and other Obligations of the Borrower accrued hereunder, shall become due and payable immediately, without presentment, demand, protest or other notice of any kind, all of which are hereby waived by the Borrower, (iii) require cash collateral for the LC Exposure as required in Section 2.06(j) hereof and (iv) exercise on behalf of itself, the Lenders and the Issuing Banks all rights and remedies available to it, the Lenders and the Issuing Banks under the Loan Documents and applicable law; and in case of any event with respect to the Borrower described in clause (g) or (h) of this Section, the Commitments shall automatically terminate and the principal of the Loans then outstanding and cash collateral for the LC Exposure, together with accrued interest thereon and all fees and other Obligations accrued hereunder and under the other Loan Documents, shall automatically become due and payable, and the obligation of the Borrower to cash collateralize the LC Exposure as provided in clause (iii) above shall automatically become effective, in each case, without presentment, demand, protest or other notice of any kind, all of which are hereby waived by the Borrower. Upon the occurrence and during the continuance of an Event of Default, the Administrative Agent may, and at the request of the Required Lenders shall, exercise any rights and remedies provided to the Administrative Agent under the Loan Documents or at law or equity.

SECTION 7.02 Application of Payments. Notwithstanding anything herein to the contrary, following the occurrence and during the continuance of an Event of Default, and notice thereof to the Administrative Agent by the Borrower or the Required Lenders, all payments received on account of the Obligations shall, subject to Section 2.21, be applied by the Administrative Agent as follows:

(i) first, to payment of that portion of the Obligations constituting fees, indemnities, expenses and other amounts payable to the Administrative Agent (including fees and disbursements and other charges of counsel to the Administrative Agent payable under Section 9.03 and amounts pursuant to Section 2.12(c) payable to the Administrative Agent in its capacity as such);

(ii) second, to payment of that portion of the Obligations constituting fees, expenses, indemnities and other amounts (other than principal, reimbursement obligations in respect of LC Disbursements, interest and Letter of Credit fees) payable to the Lenders and the Issuing Banks (including fees and disbursements and other charges of counsel to the Lenders and the Issuing Banks payable under Section 9.03) arising under the Loan Documents, ratably among them in proportion to the respective amounts described in this clause (ii) payable to them;

(iii) third, to payment of that portion of the Obligations constituting accrued and unpaid Letter of Credit fees and charges and interest on the Loans and unreimbursed LC Disbursements, ratably among the Lenders and the Issuing Banks in proportion to the respective amounts described in this clause (iii) payable to them;

(iv) fourth, (A) to payment of that portion of the Obligations constituting unpaid principal of the Loans and unreimbursed LC Disbursements and (B) to cash collateralize that portion of LC Exposure comprising the undrawn amount of Letters of Credit to the extent not otherwise cash collateralized by the Borrower pursuant to Section 2.06 or 2.21, ratably among the Lenders and the Issuing Banks in proportion to the respective amounts described in this clause (iv) payable to them; provided that (x) any such amounts applied pursuant to subclause (B) above shall be paid to the Administrative Agent for the ratable account of the applicable Issuing Bank to cash collateralize Obligations in respect of Letters of Credit, (y) subject to Section 2.06 or 2.21, amounts used to cash collateralize the aggregate amount of Letters of Credit pursuant to this clause (iv) shall be used to satisfy drawings under such Letters of Credit as they occur and (z) upon the expiration of any Letter of Credit (without any pending drawings), the pro rata share of cash collateral shall be distributed to the other Obligations, if any, in the order set forth in this Section 7.02;

(v) fifth, to the payment in full of all other Obligations, in each case ratably among the Administrative Agent, the Lenders and the Issuing Banks based upon the respective aggregate amounts of all such Obligations owing to them in accordance with the respective amounts thereof then due and payable; and

(vi) finally, the balance, if any, after all Obligations have been indefeasibly paid in full, to the Borrower or as otherwise required by law.

If any amount remains on deposit as cash collateral after all Letters of Credit have either been fully drawn or expired (without any pending drawings), such remaining amount shall be applied to the other Obligations, if any, in the order set forth above.

ARTICLE VIII

The Administrative Agent

SECTION 8.01 Authorization and Action. (a) Each Lender and the Issuing Banks hereby irrevocably appoints the entity named as Administrative Agent in the heading of this Agreement and its successors and assigns to serve as the administrative agent under the Loan Documents and each Lender and the Issuing Banks authorizes the Administrative Agent to take such actions as agent on its behalf and to exercise such powers under this Agreement and the other Loan Documents as are delegated to the Administrative Agent under such agreements and to exercise such powers as are reasonably incidental thereto. Without limiting the foregoing, each Lender and the Issuing Banks hereby authorizes the Administrative Agent to execute and deliver, and to perform its obligations under, each of the Loan Documents to which the Administrative Agent is a party, to exercise all rights, powers and remedies that the Administrative Agent may have under such Loan Documents.

(b) As to any matters not expressly provided for herein and in the other Loan Documents (including enforcement or collection), the Administrative Agent shall not be required to exercise any discretion or take any action, but shall be required to act or to refrain from acting (and shall be fully protected in so acting or refraining from acting) upon the written instructions of the Required Lenders (or such other number or percentage of the Lenders as shall be necessary, pursuant to the terms in the Loan Documents), and, unless and until revoked in writing, such instructions shall be binding upon each Lender and the Issuing Banks; provided, however, that the Administrative Agent shall not be required to take any action that (i) the Administrative Agent in good faith believes exposes it to liability unless the Administrative Agent receives an indemnification and is exculpated in a manner satisfactory to it from the Lenders and the Issuing Banks with respect to such action or (ii) is contrary to this Agreement or any other Loan Document or applicable law, including any action that may be in violation of the automatic stay under any requirement of law relating to bankruptcy, insolvency or reorganization or relief of debtors or that may effect a forfeiture, modification or termination of property of a Defaulting Lender in violation of any requirement of law relating to bankruptcy, insolvency or reorganization or relief of debtors; provided, further, that the Administrative Agent may seek clarification or direction from the Required Lenders prior to the exercise of any such instructed action and may refrain from acting until such clarification or direction has been provided. Except as expressly set forth in the Loan Documents, the Administrative Agent shall not have any duty to disclose, and shall not be liable for the failure to disclose, any information relating to the Borrower, any Subsidiary or any Affiliate of any of the foregoing that is communicated to or obtained by the Person serving as Administrative Agent or any of its Affiliates in any capacity. Nothing in this Agreement shall require the Administrative Agent to expend or risk its own funds or otherwise incur any financial liability in the performance of any of its duties hereunder or in the exercise of any of its rights or powers if it shall have reasonable grounds for believing that repayment of such funds or adequate indemnity against such risk or liability is not reasonably assured to it.

(c) In performing its functions and duties hereunder and under the other Loan Documents, the Administrative Agent is acting solely on behalf of the Lenders and the Issuing Banks (except in limited circumstances expressly provided for herein relating to the maintenance of the Register), and its duties are entirely mechanical and administrative in nature. Without limiting the generality of the foregoing:

(i) the Administrative Agent does not assume and shall not be deemed to have assumed any obligation or duty or any other relationship as the agent, fiduciary or trustee of or for any Lender, Issuing Bank or holder of any other obligation other than as expressly set forth herein and in the other Loan Documents, regardless of whether a Default or an Event of Default has occurred and is continuing (and it is understood and agreed that the use of the term “agent” (or any similar term) herein or in any other Loan Document with reference to the Administrative Agent is not intended to connote any fiduciary duty or other implied (or express) obligations arising under agency doctrine of any applicable law, and that such term is used as a matter of market custom and is intended to create or reflect only an administrative relationship between contracting parties); additionally, each Lender agrees that it will not assert any claim against the Administrative Agent based on an alleged breach of fiduciary duty by the Administrative Agent in connection with this Agreement and the transactions contemplated hereby;

(ii) nothing in this Agreement or any Loan Document shall require the Administrative Agent to account to any Lender for any sum or the profit element of any sum received by the Administrative Agent for its own account;

(d) The Administrative Agent may perform any of its duties and exercise its rights and powers hereunder or under any other Loan Document by or through any one or more sub-agents appointed by the Administrative Agent. The Administrative Agent and any such sub-agent may perform any of their respective duties and exercise their respective rights and powers through their respective Related Parties. The exculpatory provisions of this Article shall apply to any such sub-agent and to the Related Parties of the Administrative Agent and any such sub-agent, and shall apply to their respective activities pursuant to this Agreement. The Administrative Agent shall not be responsible for the negligence or misconduct of any sub-agent except to the extent that a court of competent jurisdiction determines in a final and nonappealable judgment that the Administrative Agent acted with gross negligence or willful misconduct in the selection of such sub-agent.

(e) None of any Co-Syndication Agents, the Sustainability Structuring Agent or any Arrangers shall have obligations or duties whatsoever in such capacity under this Agreement or any other Loan Document and shall incur no liability hereunder or thereunder in such capacity, but all such Persons shall have the benefit of the indemnities provided for hereunder.

(f) In case of the pendency of any proceeding with respect to the Borrower under any Federal, state or foreign bankruptcy, insolvency, receivership or similar law now or hereafter in effect, the Administrative Agent (irrespective of whether the principal of any Loan or any other obligation shall then be due and payable as herein expressed or by declaration or otherwise and irrespective of whether the Administrative Agent shall have made any demand on the Borrower) shall be entitled and empowered (but not obligated) by intervention in such proceeding or otherwise:

(i) to file and prove a claim for the whole amount of the principal and interest owing and unpaid in respect of the Loans, LC Disbursements and all other Obligations that are owing and unpaid and to file such other documents as may be necessary or advisable in order to have the claims of the Lenders, the Issuing Banks and the Administrative Agent (including any claim under Sections 2.12, 2.13, 2.15, 2.17 and 9.03) allowed in such judicial proceeding; and

(ii) to collect and receive any monies or other property payable or deliverable on any such claims and to distribute the same;

and any custodian, receiver, assignee, trustee, liquidator, sequestrator or other similar official in any such proceeding is hereby authorized by each Lender and each Issuing Bank to make such payments to the Administrative Agent and, in the event that the Administrative Agent shall consent to the making of such payments directly to the Lenders and the Issuing Banks, to pay to the Administrative Agent any amount due to it, in its capacity as the Administrative Agent, under the Loan Documents (including under Section 9.03). Nothing contained herein shall be deemed to authorize the Administrative Agent to authorize or consent to or accept or adopt on behalf of any Lender or Issuing Bank any plan of reorganization, arrangement, adjustment or composition affecting the Obligations or the rights of any Lender or Issuing Bank or to authorize the Administrative Agent to vote in respect of the claim of any Lender or Issuing Bank in any such proceeding.

(g) The provisions of this Article are solely for the benefit of the Administrative Agent, the Sustainability Structuring Agent, the Lenders and the Issuing Banks, and, except solely to the extent of the Borrower's rights to consent pursuant to and subject to the conditions set forth in this Article, none of the Borrower or any Subsidiary, or any of their respective Affiliates, shall have any rights as a third party beneficiary under any such provisions.

SECTION 8.02 Administrative Agent's Reliance, Indemnification, Etc. (a) Neither the Administrative Agent nor any of its Related Parties shall be (i) liable for any action taken or omitted to be taken by it under or in connection with this Agreement or the other Loan Documents (x) with the consent of or at the request of the Required Lenders (or such other number or percentage of the Lenders as shall be necessary, or as the Administrative Agent shall believe in good faith to be necessary, under the circumstances as provided in the Loan Documents) or (y) in the absence of its own gross negligence or willful misconduct (such absence to be presumed unless otherwise determined by a court of competent jurisdiction by a final and nonappealable judgment) or (ii) responsible in any manner to any of the Lenders for any recitals, statements, representations or warranties made by the Borrower or any officer thereof contained in this Agreement or any other Loan Document or in any certificate, report, statement or other document referred to or provided for in, or received by the Administrative Agent under or in connection with, this Agreement or any other Loan Document or for the value, validity, effectiveness, genuineness, enforceability or sufficiency of this Agreement or any other Loan Document (including, for the avoidance of doubt, in connection with the Administrative Agent's reliance on any Electronic Signature transmitted by telecopy, emailed pdf, or any other electronic means that reproduces an image of an actual executed signature page) or for any failure of the Borrower to perform its obligations hereunder or thereunder.

(b) The Administrative Agent shall be deemed not to have knowledge of any Default unless and until written notice thereof (stating that it is a "notice of default") is given to the Administrative Agent by the Borrower, a Lender or any Issuing Bank, and the Administrative Agent shall not be responsible for or have any duty to ascertain or inquire into (i) any statement, warranty or representation made in or in connection with any Loan Document, (ii) the contents of any certificate, report or other document delivered thereunder or in connection therewith, (iii) the performance or observance of any of the covenants, agreements or other terms or conditions set forth in any Loan Document or the occurrence of any Default, (iv) the sufficiency, validity, enforceability, effectiveness or genuineness of any Loan Document or any other agreement, instrument or document, or (v) the satisfaction of any condition set forth in Article IV or elsewhere in any Loan Document, other than to confirm receipt of items expressly required to be delivered to the Administrative Agent or satisfaction of any condition that expressly refers to the matters described therein being acceptable or satisfactory to the Administrative Agent.

(c) Without limiting the foregoing, the Administrative Agent (i) may treat the payee of any promissory note as its holder until such promissory note has been assigned in accordance with Section 9.04, (ii) may rely on the Register to the extent set forth in Section 9.04(b), (iii) may consult with legal counsel (including counsel to the Borrower), independent public accountants and other experts selected by it, and shall not be liable for any action taken or omitted to be taken in good faith by it in accordance with the advice of such counsel, accountants or experts, (iv) makes no warranty or representation to any Lender or Issuing Bank and shall not be responsible to any Lender or Issuing Bank for any statements, warranties or representations made by or on behalf of the Borrower in connection with this Agreement or any other Loan Document, (v) in determining compliance with any condition hereunder to the making of a Loan, or the issuance of a Letter of Credit, that by its terms must be fulfilled to the satisfaction of a Lender or any Issuing Bank, may presume that such condition is satisfactory to such Lender or Issuing Bank unless the Administrative Agent shall have received notice to the contrary from such Lender or Issuing Bank sufficiently in advance of the making of such Loan or the issuance of such Letter of Credit and (vi) shall be entitled to rely on, and shall incur no liability under or in respect of this Agreement or any other Loan Document by acting upon, any notice, consent, certificate or other instrument or writing (which writing may be a fax, any electronic message, Internet or intranet website posting or other distribution) or any statement made to it orally or by telephone and believed by it to be genuine and signed or sent or otherwise authenticated by the proper party or parties (whether or not such Person in fact meets the requirements set forth in the Loan Documents for being the maker thereof).

SECTION 8.03 Posting of Communications. (a) The Borrower agrees that the Administrative Agent may, but shall not be obligated to, make any Communications available to the Lenders and the Issuing Banks by posting the Communications on IntraLinks™, DebtDomain, SyndTrak, ClearPar or any other electronic platform chosen by the Administrative Agent to be its electronic transmission system (the "Approved Electronic Platform").

(b) Although the Approved Electronic Platform and its primary web portal are secured with generally-applicable security procedures and policies implemented or modified by the Administrative Agent from time to time (including, as of the Restatement Effective Date, a user ID/password authorization system) and the Approved Electronic Platform is secured through a per-deal authorization method whereby each user may access the Approved Electronic Platform only on a deal-by-deal basis, each of the Lenders, the Issuing Banks and the Borrower acknowledges and agrees that the distribution of material through an electronic medium is not necessarily secure, that the Administrative

Agent is not responsible for approving or vetting the representatives or contacts of any Lender that are added to the Approved Electronic Platform, and that there are confidentiality and other risks associated with such distribution. Each of the Lenders, the Issuing Banks and the Borrower hereby approves distribution of the Communications through the Approved Electronic Platform and understands and assumes the risks of such distribution.

(c) THE APPROVED ELECTRONIC PLATFORM AND THE COMMUNICATIONS ARE PROVIDED "AS IS" AND "AS AVAILABLE". THE APPLICABLE PARTIES (AS DEFINED BELOW) DO NOT WARRANT THE ACCURACY OR COMPLETENESS OF THE COMMUNICATIONS, OR THE ADEQUACY OF THE APPROVED ELECTRONIC PLATFORM AND EXPRESSLY DISCLAIM LIABILITY FOR ERRORS OR OMISSIONS IN THE APPROVED ELECTRONIC PLATFORM AND THE COMMUNICATIONS. NO WARRANTY OF ANY KIND, EXPRESS, IMPLIED OR STATUTORY, INCLUDING ANY WARRANTY OF MERCHANTABILITY, FITNESS FOR A PARTICULAR PURPOSE, NON-INFRINGEMENT OF THIRD PARTY RIGHTS OR FREEDOM FROM VIRUSES OR OTHER CODE DEFECTS, IS MADE BY THE APPLICABLE PARTIES IN CONNECTION WITH THE COMMUNICATIONS OR THE APPROVED ELECTRONIC PLATFORM. IN NO EVENT SHALL THE ADMINISTRATIVE AGENT, ANY ARRANGERS, THE SUSTAINABILITY STRUCTURING AGENT, ANY CO-SYNDICATION AGENTS OR ANY OF THEIR RESPECTIVE RELATED PARTIES (COLLECTIVELY, "APPLICABLE PARTIES") HAVE ANY LIABILITY TO THE BORROWER, ANY LENDER, ANY ISSUING BANK OR ANY OTHER PERSON OR ENTITY FOR DAMAGES OF ANY KIND, INCLUDING DIRECT OR INDIRECT, SPECIAL, INCIDENTAL OR CONSEQUENTIAL DAMAGES, LOSSES OR EXPENSES (WHETHER IN TORT, CONTRACT OR OTHERWISE) ARISING OUT OF THE BORROWER'S OR THE ADMINISTRATIVE AGENT'S TRANSMISSION OF COMMUNICATIONS THROUGH THE INTERNET OR THE APPROVED ELECTRONIC PLATFORM.

"Communications" means, collectively, any notice, demand, communication, information, document or other material provided by or on behalf of the Borrower pursuant to any Loan Document or the transactions contemplated therein which is distributed by the Administrative Agent, any Lender or any Issuing Bank by means of electronic communications pursuant to this Section, including through an Approved Electronic Platform.

(d) Each Lender and Issuing Bank agrees that notice to it (as provided in the next sentence) specifying that Communications have been posted to the Approved Electronic Platform shall constitute effective delivery of the Communications to such Lender for purposes of the Loan Documents. Each Lender and Issuing Bank agrees (i) to notify the Administrative Agent in writing (which could be in the form of electronic communication) from time to time of such Lender's or Issuing Bank's (as applicable) email address to which the foregoing notice may be sent by electronic transmission and (ii) that the foregoing notice may be sent to such email address.

(e) Each of the Lenders, the Issuing Banks and the Borrower agrees that the Administrative Agent may, but (except as may be required by applicable law) shall not be obligated to, store the Communications on the Approved Electronic Platform in accordance with the Administrative Agent's generally applicable document retention procedures and policies.

(f) Nothing herein shall prejudice the right of the Administrative Agent, any Lender or any Issuing Bank to give any notice or other communication pursuant to any Loan Document in any other manner specified in such Loan Document.

SECTION 8.04 The Administrative Agent Individually. With respect to its Commitment, Loans, Letter of Credit Commitments and Letters of Credit, the Person serving as the Administrative Agent shall have and may exercise the same rights and powers hereunder and is subject to the same obligations and liabilities as and to the extent set forth herein for any other Lender or Issuing Bank, as the case may be. The terms "Issuing Bank", "Lenders", "Required Lenders" and any similar terms shall, unless the context clearly otherwise indicates, include the Administrative Agent in its individual capacity as a Lender, Issuing Bank or as one of the Required Lenders, as applicable. The Person serving as the Administrative Agent and its Affiliates may accept deposits from, lend money to, own securities of, act as the financial advisor or in any other advisory capacity for and generally engage in any kind of banking, trust or other business with, the Borrower, any Subsidiary or any Affiliate of any of the foregoing as if such Person was not acting as the Administrative Agent and without any duty to account therefor to the Lenders or the Issuing Banks.

SECTION 8.05 Successor Administrative Agent. Subject to the appointment and acceptance of a successor Administrative Agent as provided in this paragraph, the Administrative Agent may resign at any time by notifying the Lenders, the Issuing Banks and the Borrower. Upon any such resignation, the Required Lenders shall have the right, in consultation with the Borrower, to appoint a successor. If no successor shall have been so appointed by the Required Lenders and shall have accepted such appointment within 30 days after the retiring Administrative Agent gives notice of its resignation, then the retiring Administrative Agent may, on behalf of the Lenders and the Issuing Banks, appoint a successor Administrative Agent which shall be a bank with an office in New York, New York, or an Affiliate of any such bank. Upon the acceptance of its appointment as Administrative Agent hereunder by a successor, such successor shall succeed to and become vested with all the rights, powers, privileges and duties of the retiring Administrative Agent, and the retiring Administrative Agent shall be discharged from its duties and obligations hereunder. The fees payable by the Borrower to a successor Administrative Agent shall be the same as those payable to its predecessor unless otherwise agreed between the Borrower and such successor. After the Administrative Agent's resignation hereunder, the provisions of this Article and Section 9.03, as well as any exculpatory, reimbursement and indemnification provisions set forth in any other Loan Document, shall continue in effect for the benefit of such retiring Administrative Agent, its sub agents and their respective Related Parties in respect of any actions taken or omitted to be taken by any of them while it was acting as Administrative Agent.

SECTION 8.06 Acknowledgments of Lenders and Issuing Banks. (a) Each Lender and each Issuing Bank represents and warrants that (i) the Loan Documents set forth the terms of a commercial lending facility, (ii) it is engaged in making, acquiring or holding commercial loans and in providing other facilities set forth herein as may be applicable to such Lender or Issuing Bank, in each case in the ordinary course of business, and not for the purpose of purchasing, acquiring or holding any other type of financial instrument (and each Lender and each Issuing Bank agrees not to assert a claim in contravention of the foregoing), (iii) it has, independently and without reliance upon the Administrative Agent, any Arranger, any Co-Syndication Agent, the Sustainability Structuring Agent or any other Lender or Issuing Bank, or any of the Related Parties of any of the foregoing, and based on such documents and information as it has deemed appropriate, made its own credit analysis and decision to enter into this Agreement as a Lender, and to make, acquire or hold Loans hereunder and (iv) it is sophisticated with respect to decisions to make, acquire and/or hold commercial loans and to provide other facilities set forth herein, as may be applicable to such Lender or such Issuing Bank, and either it, or the Person exercising discretion in making its decision to make, acquire and/or hold such commercial loans or to provide such other facilities, is experienced in making, acquiring or holding such commercial loans or providing such other facilities. Each Lender and each Issuing Bank also acknowledges that it will, independently and without reliance upon the Administrative Agent, any Arranger, any Co-Syndication Agent, the Sustainability Structuring Agent or any other Lender or Issuing Bank, or any of the Related Parties of any of the foregoing, and based on such documents and information (which may contain material, non-public information within the meaning of the United States securities laws concerning the Borrower and its Affiliates) as it shall from time to time deem appropriate, continue to make its own decisions in taking or not taking action under or based upon this Agreement, any other Loan Document or any related agreement or any document furnished hereunder or thereunder. Each Lender and each Issuing Bank also acknowledges and agrees that none of the Administrative Agent, any Arranger, any Co-Syndication Agent, the Sustainability Structuring Agent acting in such capacities have made any assurances as to (i) whether the credit facility evidenced by the Loan Documents (the "Facility") meets such Lender's or Issuing Bank's criteria or expectations with regard to environmental impact and sustainability performance, (ii) whether any characteristics of the Facility, including the characteristics of the relevant key performance indicators to which the Borrower will link a potential margin step-up or step-down, including their environmental and sustainability criteria, meet any industry standards for sustainability-linked credit facilities and (b) each Lender and Issuing Bank has performed its own independent investigation and analysis of the Facility and whether the Facility meets its own criteria or expectations with regard to environmental impact and/or sustainability performance.

(b) Each Lender, by delivering its signature page to this Agreement on the Restatement Effective Date, or delivering its signature page to an Assignment and Assumption or any other Loan Document pursuant to which it shall become a Lender hereunder, shall be deemed to have acknowledged receipt of, and consented to and approved, each Loan Document and each other document required to be delivered to, or be approved by or satisfactory to, the Administrative Agent or the Lenders on the Restatement Effective Date.

(c)

(i) Each Lender hereby agrees that (x) if the Administrative Agent notifies such Lender that the Administrative Agent has determined in its sole discretion that any funds received by such Lender from the Administrative Agent or any of its Affiliates (whether as a payment, prepayment or repayment of principal, interest, fees or otherwise; individually and collectively, a "Payment") were erroneously transmitted to such Lender (whether or not known to such Lender), and demands the return of such Payment (or a portion thereof), such Lender shall promptly, but in no event later than one Business Day thereafter, return to the Administrative Agent the amount of any such Payment (or portion thereof) as to which such a demand was made in same day funds, together with interest thereon in respect of each day from and including the date such Payment (or portion thereof) was received by such Lender to the date such amount is repaid to the Administrative Agent at the greater of the NYFRB Rate and a rate determined by the Administrative Agent in accordance with banking industry rules on interbank compensation from time to time in effect, and (y) to the extent permitted by applicable law, such Lender shall not assert, and hereby waives, as to the Administrative Agent, any claim, counterclaim, defense or right of set-off or recoupment with respect to any demand, claim or counterclaim by the Administrative Agent for the return of any Payments received, including without limitation any defense based on "discharge for value" or any similar doctrine. A notice of the Administrative Agent to any Lender under this Section 8.06(c) shall be conclusive, absent manifest error.

(ii) Each Lender hereby further agrees that if it receives a Payment from the Administrative Agent or any of its Affiliates (x) that is in a different amount than, or on a different date from, that specified in a notice of payment sent by the Administrative Agent (or any of its Affiliates) with respect to such Payment (a "Payment Notice") or (y) that was not preceded or accompanied by a Payment Notice, it shall be on notice, in each such case, that an error has been made with respect to such Payment. Each Lender agrees that, in each such case, or if it otherwise becomes aware a Payment (or portion thereof) may have been sent in error, such Lender shall promptly notify the Administrative Agent of such occurrence and, upon demand from the Administrative Agent, it shall promptly, but in no event later than one Business Day thereafter, return to the Administrative Agent the amount of any such Payment (or portion thereof) as to which such a demand was made in same day funds, together with interest thereon in respect of each day from and including the date such Payment (or portion thereof) was received by such Lender to the date such amount is repaid to the Administrative Agent at the greater of the NYFRB Rate and a rate determined by the Administrative Agent in accordance with banking industry rules on interbank compensation from time to time in effect.

(iii) The Borrower hereby agrees that (x) in the event an erroneous Payment (or portion thereof) are not recovered from any Lender that has received such Payment (or portion thereof) for any reason, the Administrative Agent shall be subrogated to all the rights of such Lender with respect to such amount and (y) an erroneous Payment shall not pay, prepay, repay, discharge or otherwise satisfy any Obligations owed by the Borrower.

(iv) Each party's obligations under this Section 8.06(c) shall survive the resignation or replacement of the Administrative Agent or any transfer of rights or obligations by, or the replacement of, a Lender, the termination of the Commitments or the repayment, satisfaction or discharge of all Obligations under any Loan Document.

SECTION 8.07 Certain ERISA Matters. (a) Each Lender (x) represents and warrants, as of the date such Person became a Lender party hereto, to, and (y) covenants, from the date such Person became a Lender party hereto to the date such Person ceases being a Lender party hereto, for the benefit of, the Administrative Agent, and each Arranger and their respective Affiliates, and not, for the avoidance of doubt, to or for the benefit of the Borrower, that at least one of the following is and will be true:

(i) such Lender is not using "plan assets" (within the meaning of the Plan Asset Regulations) of one or more Benefit Plans in connection with the Loans, the Letters of Credit or the Commitments,

(ii) the transaction exemption set forth in one or more PTEs, such as PTE 84-14 (a class exemption for certain transactions determined by independent qualified professional asset managers), PTE 95-60 (a class exemption for certain transactions involving insurance company general accounts), PTE 90-1 (a class exemption for certain transactions involving insurance company pooled separate accounts), PTE 91-38 (a class exemption for certain transactions involving bank collective investment funds) or PTE 96-23 (a class exemption for certain transactions determined by in-house asset managers), is applicable with respect to such Lender's entrance into, participation in, administration of and performance of the Loans, the Letters of Credit, the Commitments and this Agreement, and the conditions for exemptive relief thereunder are and will continue to be satisfied in connection therewith,

(iii) (A) such Lender is an investment fund managed by a "Qualified Professional Asset Manager" (within the meaning of Part VI of PTE 84-14), (B) such Qualified Professional Asset Manager made the investment decision on behalf of such Lender to enter into, participate in, administer and perform the Loans, the Letters of Credit, the Commitments and this Agreement, (C) the entrance into, participation in, administration of and performance of the Loans, the Letters of Credit, the Commitments and this Agreement satisfies the requirements of sub-sections (b) through (g) of Part I of PTE 84-14 and (D) to the best knowledge of such Lender, the requirements of subsection (a) of Part I of PTE 84-14 are satisfied with respect to such Lender's entrance into, participation in, administration of and performance of the Loans, the Letters of Credit, the Commitments and this Agreement, or

(iv) such other representation, warranty and covenant as may be agreed in writing between the Administrative Agent, in its sole discretion, and such Lender.

(b) In addition, unless either (1) sub-clause (i) in the immediately preceding clause (a) is true with respect to a Lender or (2) a Lender has provided another representation, warranty and covenant in accordance with sub-clause (iv) in the immediately preceding clause (a), such Lender further (x) represents and warrants, as of the date such Person became a Lender party hereto, to, and (y) covenants, from the date such Person became a Lender party hereto to the date such Person ceases being a Lender party hereto, for the benefit of, the Administrative Agent, each Arranger and their respective Affiliates, and not, for the avoidance of doubt, to or for the benefit of the Borrower, that none of the Administrative Agent, or any Arranger, any Co-Syndication Agent, the Sustainability Structuring Agent or any of their Affiliates is a fiduciary with respect to the assets of such Lender involved in such Lender's entrance into, participation in, administration of and performance of the Loans, the Letters of Credit, the Commitments and this Agreement (including in connection with the reservation or exercise of any rights by the Administrative Agent under this Agreement, any Loan Document or any documents related hereto or thereto).

(c) The Administrative Agent, and each Arranger hereby informs the Lenders that each such Person is not undertaking to provide impartial investment advice, or to give advice in a fiduciary capacity, in connection with the transactions contemplated hereby, and that such Person has a financial interest in the transactions contemplated hereby in that such Person or an Affiliate thereof (i) may receive interest or other payments with respect to the Loans, the Letters of Credit, the Commitments and this Agreement, (ii) may recognize a gain if it extended the Loans, the Letters of Credit or the Commitments for an amount less than the amount being paid for an interest in the Loans, the Letters of Credit or the Commitments by such Lender or (iii) may receive fees or other payments in connection with the transactions contemplated hereby, the Loan Documents or otherwise, including structuring fees, commitment fees, arrangement fees, facility fees, upfront fees, underwriting fees, ticking fees, agency fees, administrative agent or collateral agent fees, utilization fees, minimum usage fees, letter of credit fees, fronting fees, deal-away or alternate transaction fees, amendment fees, processing fees, term out premiums, banker's acceptance fees, breakage or other early termination fees or fees similar to the foregoing.

SECTION 8.08 Certain Sustainability Matters. Each party hereto hereby agrees that neither the Administrative Agent nor the Sustainability Structuring Agent shall have any responsibility for (or liability in respect of) reviewing, auditing or otherwise evaluating any calculation by the Borrower of any Sustainability Facility Fee Adjustment or any Sustainability Rate Adjustment (or any of the data or computations that are part of or related to any such calculation) set forth in any Pricing Certificate (and the Administrative Agent may rely conclusively on any such certificate, without further inquiry).

ARTICLE IX

Miscellaneous

SECTION 9.01 Notices. (a) Except in the case of notices and other communications expressly permitted to be given by telephone (and subject to paragraph (b) below), all notices and other communications provided for herein shall be in writing and shall be delivered by hand or overnight courier service, mailed by certified or registered mail or sent by telecopy, as follows:

(i) if to the Borrower, to it at 250 SW Taylor Street, Portland, OR 97204, Attention of Brody J. Wilson, Vice President, Treasurer, Chief Accounting Officer and Controller (Telecopy No. (503) 220-2584; Telephone No. (503) 610-7176; Email Address: brody.wilson@nwnatural.com);

(ii) if to the Administrative Agent, to JPMorgan Chase Bank, N.A., 131 S Dearborn St, Floor 04, Chicago, IL 60603-5506, Attention of Kathryn V Tyler (Telecopy No. (844) 490-5663, Telephone No. (312) 954-0447; Email Address: katy.tyler@chase.com);

(iii) If to the Swingline Lender, to it at JPMorgan Chase Bank, N.A., 131 S Dearborn St, Floor 04, Chicago, IL 60603-5506, Attention of Kathryn V Tyler (Telecopy No. (844) 490-5663, Telephone No. (312) 954-0447; Email Address: katy.tyler@chase.com);

(iv) if to the Issuing Banks,

(A) in the case of JPMorgan Chase Bank, N.A, to it at JPMorgan Chase Bank, N.A., 8181 Communications Pkwy, Building B, 6th Floor, Plano, TX 75024, Attention of Hamza Tariq (Telephone No. (972) 324-2325; Email Address: hamza.tariq@jpmorgan.com);

(B) if to Bank of America, N.A. to it at Bank of America, N.A., Commercial Banking Credit Products, OR1-129-17-01
121, SW Morrison St., Suite 1700, Portland, OR 97204, Attention of Daryl K. Hogge (Telecopy No. (312) 453-5325; Telephone No. (503) 795-6469; Email Address: daryl.k.hogge@baml.com);

(C) if to U.S. Bank National Association to it at U.S. Bank National Association, Corporate & Commercial Banking, 209 S. LaSalle St., Chicago, IL 60604 , MK-IL-RY3S, Attention of John M. Eyerman (Telephone No. (312) 325-2032; Email Address: john.eyerman@usbank.com); and

(D) if to Wells Fargo Bank, National Association to it at Wells Fargo Bank, National Association, Wells Fargo Corporate Banking, 90 S. Seventh Street, 15th Floor MAC: N9305-15G, Minneapolis, MN 55402 Attention of Gregory R. Gredvig (Telecopy No. (612) 316-0506; Telephone No. (612) 667-4832; Email Address: gregory.r.gredvig@wellsfargo.com); and

(v) if to any other Lender, to it at its address (or telecopy number) set forth in its Administrative Questionnaire.

Notices sent by hand or overnight courier service, or mailed by certified or registered mail, shall be deemed to have been given when received; notices sent by facsimile shall be deemed to have been given when sent (except that, if not given during normal business hours for the recipient, shall be deemed to have been given at the opening of business on the next Business Day for the recipient). Notices delivered through Approved Electronic Platforms, to the extent provided in paragraph (b) below, shall be effective as provided in said paragraph (b).

(b) Notices and other communications to the Lenders and the Issuing Banks hereunder may be delivered or furnished by using Approved Electronic Platforms pursuant to procedures approved by the Administrative Agent; provided that the foregoing shall not apply to notices pursuant to Article II unless otherwise agreed by the Administrative Agent and the applicable Lender. The Administrative Agent or the Borrower may, in its discretion, agree to accept notices and other communications to it hereunder by electronic communications pursuant to procedures approved by it; provided that approval of such procedures may be limited to particular notices or communications.

Unless the Administrative Agent otherwise prescribes, (i) notices and other communications sent to an e-mail address shall be deemed received upon the sender's receipt of an acknowledgement from the intended recipient (such as by the "return receipt requested" function, as available, return e-mail or other written acknowledgement), and (ii) notices or communications posted to an Internet or intranet website shall be deemed received upon the deemed receipt by the intended recipient, at its e-mail address as described in the foregoing clause (i), of notification that such notice or communication is available and identifying the website address therefor; provided that, for both clauses (i) and (ii) above, if such notice, email or other communication is not sent during the normal business hours of the recipient, such notice or communication shall be deemed to have been sent at the opening of business on the next Business Day for the recipient.

(c) Any party hereto may change its address or telecopy number for notices and other communications hereunder by written notice to the other parties hereto.

SECTION 9.02 Waivers; Amendments. (a) No failure or delay by the Administrative Agent, any Issuing Bank or any Lender in exercising any right or power hereunder or under any other Loan Document shall operate as a waiver thereof, nor shall any single or partial exercise of any such right or power, or any abandonment or discontinuance of steps to enforce such a right or power, preclude any other or further exercise thereof or the exercise of any other right or power. The rights and remedies of the Administrative Agent, the Issuing Banks and the Lenders hereunder and under the other Loan Documents are cumulative and are not exclusive of any rights or remedies that they would otherwise have. No waiver of any provision of this Agreement or consent to any departure by the Borrower therefrom shall in any event be effective unless the same shall be permitted by paragraph (b) of this Section, and then such waiver or consent shall be effective only in the specific instance and for the purpose for which given. Without limiting the generality of the foregoing, the making of a Loan or issuance of a Letter of Credit shall not be construed as a waiver of any Default, regardless of whether the Administrative Agent, any Lender or any Issuing Bank may have had notice or knowledge of such Default at the time.

(b) Subject to Section 2.14(b), (c) and (d), and clauses (c) and (d) below, neither this Agreement nor any provision hereof may be waived, amended or modified except pursuant to an agreement or agreements in writing entered into by the Borrower and the Required Lenders or by the Borrower and the Administrative Agent with the consent of the Required Lenders; provided that no such agreement shall (i) increase the Commitment of any Lender without the written consent of such Lender, (ii) reduce the principal amount of any Loan or LC Disbursement or reduce the rate of interest thereon, or reduce any fees payable hereunder, without the written consent of each Lender directly affected thereby, (iii) postpone the scheduled date of payment of the principal amount of any Loan or LC Disbursement, or any interest thereon, or any fees payable hereunder, or reduce the amount of, waive or excuse any such payment, or postpone the scheduled date of expiration of any Commitment, without the written consent of each Lender directly affected thereby, (iv) change Section 2.09(c) or Section 2.18(b) or (d) in a manner that would alter the ratable reduction of Commitments or pro rata sharing of payments required thereby, without the written consent of each Lender, (v) change the payment waterfall provisions of Section 2.21(b) or 7.02 without the written consent of each Lender or (vi) change any of the provisions of this Section or the definition of "Required Lenders" or any other provision hereof specifying the number or percentage of Lenders required to waive, amend or modify any rights hereunder or make any determination or grant any consent hereunder, without the written consent of each Lender (it being understood that, solely with the consent of the parties prescribed by Section 2.20 to be parties to an Incremental Term Loan Amendment, Incremental Term Loans may be included in the determination of Required Lenders on substantially the same basis as the Commitments and the Revolving Loans are included on the Restatement Effective Date); provided further that no such agreement shall amend, modify or otherwise affect the rights or duties of the Administrative Agent, any Issuing Bank or the Swingline Lender hereunder without the prior written consent of the Administrative Agent, such Issuing Bank or the Swingline Lender, as the case may be (it being understood that any change to Section 2.21 shall require the consent of the Administrative Agent, the Issuing Banks and the Swingline Lender); provided further, that no such agreement shall amend or modify the provisions of Section 2.06 or any letter of credit application and any bilateral agreement between the Borrower and any Issuing Bank regarding such Issuing Bank's Letter of Credit Commitment or the respective rights and obligations between the Borrower and such Issuing Bank in connection with the issuance of Letters of Credit without the prior written consent of the Administrative Agent and such Issuing Bank, respectively. Notwithstanding the foregoing, no consent with respect to any amendment, waiver or other modification of this Agreement shall be required of any Defaulting Lender, except with respect to any amendment, waiver or other modification referred to in clause (i), (ii) or (iii) of the first proviso of this paragraph and then only in the event such Defaulting Lender shall be directly affected by such amendment, waiver or other modification.

(c) Notwithstanding the foregoing, this Agreement and any other Loan Document may be amended (or amended and restated) with the written consent of the Required Lenders, the Administrative Agent and the Borrower (x) to add one or more credit facilities (in addition to the Incremental Term Loans pursuant to an Incremental Term Loan Amendment) to this Agreement and to permit extensions of credit from time to time outstanding thereunder and the accrued interest and fees in respect thereof to share ratably in the benefits of this Agreement and the other Loan Documents with the Revolving Loans, Incremental Term Loans and the accrued interest and fees in respect thereof and (y) to include appropriately the Lenders holding such credit facilities in any determination of the Required Lenders and Lenders.

(d) If the Administrative Agent and the Borrower acting together identify any ambiguity, omission, mistake, typographical error or other defect in any provision of this Agreement or any other Loan Document, then the Administrative Agent and the Borrower shall be permitted to amend, modify or supplement such provision to cure such ambiguity, omission, mistake, typographical error or other defect, and such amendment shall become effective without any further action or consent of any other party to this Agreement.

SECTION 9.03 Expenses; Limitation of Liability; Indemnity; Etc.

(a) Expenses. The Borrower shall pay (i) all reasonable out-of-pocket expenses incurred by the Administrative Agent, the Co-Syndication Agents, the Sustainability Structuring Agent, the Arrangers and their respective Affiliates, including the reasonable fees, charges and disbursements of counsel and other advisors and professionals for such Persons, in connection with the syndication and distribution (including, without limitation, via the internet or through a service such as Intralinks) of the credit facilities provided for herein, the investigation, preparation, negotiation, documentation, collection and administration of this Agreement and the other Loan Documents or any amendments, modifications or waivers of the provisions hereof or thereof (whether or not the transactions contemplated hereby or thereby shall be consummated), (ii) all reasonable out-of-pocket expenses incurred by any Issuing Bank in connection with the issuance, amendment, renewal or extension of any Letter of Credit or any demand for payment thereunder and (iii) all out-of-pocket expenses incurred by the Administrative Agent, the Co-Syndication Agents, the Sustainability Structuring Agent, any Arranger, any Issuing Bank or any Lender, including the fees, charges and disbursements of any counsel for the Administrative Agent, the Co-Syndication Agents, the Sustainability Structuring Agent, any Arranger, any Issuing Bank or any Lender, in connection with the enforcement or protection of its rights in connection with this Agreement and any other Loan Document, including its rights under this Section, or in connection with the Loans made or Letters of Credit issued hereunder, including all such out-of-pocket expenses incurred during any workout, restructuring or negotiations in respect of such Loans or Letters of Credit.

(b) Indemnity. The Borrower shall indemnify the Administrative Agent, the Co-Syndication Agents, the Sustainability Structuring Agent, each Arranger, any Issuing Bank and each Lender, and each Related Party of any of the foregoing Persons (each such Person being called an "Indemnitee") against, and hold each Indemnitee harmless from, any and all Liabilities and related expenses, including the fees, charges and disbursements of any counsel for any Indemnitee, incurred by or asserted against any Indemnitee arising out of, in connection with, or as a result of (i) the execution or delivery of this Agreement, any other Loan Document or any agreement or instrument contemplated hereby or thereby, the performance by the parties hereto of their respective obligations hereunder or thereunder or the consummation of the Transactions or any other transactions contemplated hereby, (ii) any Loan or Letter of Credit or the use of the proceeds therefrom (including any refusal by any Issuing Bank to honor a demand for payment under a Letter of Credit if the documents presented in connection with such demand do not strictly comply with the terms of such Letter of Credit), (iii) any actual or alleged presence or release of Hazardous Materials on or from any property owned or operated by the Borrower or any of its Subsidiaries, or any Environmental Liability related in any way to the Borrower or any of its Subsidiaries, or (iv) any actual or prospective Proceeding relating to any of the foregoing, whether or not such Proceeding is brought by the Borrower or its respective equity holders, Affiliates, creditors or any other third Person and whether based on contract, tort or any other theory and regardless of whether any Indemnitee is a party thereto; provided that such indemnity shall not, as to any Indemnitee, be available to the extent that such Liabilities or related expenses (A) result from a claim brought by the Borrower or any of its Subsidiaries against such Indemnitee for material breach of such Indemnitee's or any of its Related Parties' obligations under any Loan Document if the Borrower or such Subsidiary has obtained a final and nonappealable judgment in its favor on such claim as determined by a court of competent jurisdiction or (B) are determined by a court of competent jurisdiction by final and nonappealable judgment to have resulted from the gross negligence or willful misconduct of such Indemnitee. This Section 9.03(b) shall not apply with respect to Taxes other than any Taxes that represent losses, claims or damages arising from any non-Tax claim.

(c) Lender Reimbursement. Each Lender severally agrees to pay any amount required to be paid by the Borrower under paragraph (a) or (b) of this Section 9.03 to the Administrative Agent, the Co-Syndication Agents, the Sustainability Structuring Agent the Arrangers, the Issuing Banks and the Swingline Lender, and each Related Party of any of the foregoing Persons (each, an "Agent-Related Person") (to the extent not reimbursed by the Borrower and without limiting the obligation of the Borrower to do so), ratably according to their respective Applicable Percentage in effect on the date on which such payment is sought under this Section (or, if such payment is sought after the date upon which the Commitments shall have terminated and the Loans shall have been paid in full, ratably in accordance with such Applicable Percentage immediately prior to such date), and agrees to indemnify and hold each Agent-Related Person harmless from and against any and all Liabilities and related expenses, including the fees, charges and disbursements of any kind whatsoever that may at any time (whether before or after the payment of the Loans) be imposed on, incurred by or asserted against such Agent-Related Person in any way relating to or arising out of the Commitments, this Agreement, any of the other Loan Documents or any documents contemplated by or referred to herein or therein or the transactions contemplated hereby or thereby or any action taken or omitted by such Agent-Related Person under or in connection with any of the foregoing; provided that the unreimbursed expense or Liability or related expense, as the case may be, was incurred by or asserted against such Agent-Related Person in its capacity as such; provided further that no Lender shall be liable for the payment of any portion of such Liabilities, costs, expenses or disbursements that are found by a final and nonappealable decision of a court of competent jurisdiction to have resulted from such Agent-Related Person's gross negligence or willful misconduct. The agreements in this Section shall survive the termination of this Agreement and the payment of the Loans and all other amounts payable hereunder.

(d) Limitation of Liability. To the extent permitted by applicable law, (i) the Borrower shall not assert, and hereby waives, any claim against the Administrative Agent, any Arranger, any Co-Syndication Agent, the Sustainability Structuring Agent, any Issuing Bank and any Lender, and any Related Party of any of the foregoing Persons (each such Person being called a "Lender-Related Person") for any Liabilities arising from the use by others of information or other materials obtained through telecommunications, electronic or other information transmission systems (including the Internet), and (ii) no party hereto shall assert, and each such party hereby waives, any claim against any other party hereto, on any theory of liability, for special, indirect, consequential or punitive damages (as opposed to direct or actual damages) arising out of, in connection with, or as a result of, this Agreement, any other Loan Document or any agreement or instrument contemplated hereby or thereby, the Transactions, any Loan or Letter of Credit or the use of the proceeds thereof; provided that, nothing in this clause (d)(ii) shall relieve the Borrower of any obligation it may have to indemnify an Indemnitee against special, indirect, consequential or punitive damages asserted against such Indemnitee by a third party.

(e) Payments. All amounts due under this Section shall be payable promptly after written demand therefor.

SECTION 9.04 Successors and Assigns. (a) The provisions of this Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns permitted hereby (including any Affiliate of any Issuing Bank that issues any Letter of Credit), except that (i) the Borrower may not assign or otherwise transfer any of its rights or obligations hereunder without the prior written consent of each Lender (and any attempted assignment or transfer by the Borrower without such consent shall be null and void) and (ii) no Lender may assign or otherwise transfer its rights or obligations hereunder except in accordance with this Section. Nothing in this Agreement, expressed or implied, shall be construed to confer upon any Person (other than the parties hereto, their respective successors and assigns permitted hereby (including any Affiliate of any Issuing Bank that issues any Letter of Credit), Participants (to the extent provided in paragraph (c) of this Section) and, to the extent expressly contemplated hereby, the Related Parties of each of the Administrative Agent, the Issuing Banks and the Lenders) any legal or equitable right, remedy or claim under or by reason of this Agreement.

(b) (i) Subject to the conditions set forth in paragraph (b)(ii) below, any Lender may assign to one or more Persons (other than an Ineligible Institution) all or a portion of its rights and obligations under this Agreement (including all or a portion of its Commitment, participations in Letters of Credit and the Loans at the time owing to it) with the prior written consent (such consent not to be unreasonably withheld) of:

(A) the Borrower (provided that the Borrower shall be deemed to have consented to any such assignment unless it shall object thereto by written notice to the Administrative Agent within ten (10) Business Days after having received notice thereof); provided, further, that no consent of the Borrower shall be required for an assignment to a Lender, an Affiliate of a Lender, an Approved Fund or, if an Event of Default has occurred and is continuing, any other assignee;

(B) the Administrative Agent; provided, that no consent of the Administrative Agent shall be required for an assignment of any Commitment to an assignee that is a Lender (other than a Defaulting Lender) with a Commitment immediately prior to giving effect to such assignment;

(C) the Issuing Banks; and

(D) the Swingline Lender.

(ii) Assignments shall be subject to the following additional conditions:

(A) except in the case of an assignment to a Lender or an Affiliate of a Lender or an Approved Fund or an assignment of the entire remaining amount of the assigning Lender's Commitment or Loans of any Class, the amount of the Commitment or Loans of the assigning Lender subject to each such assignment (determined as of the date the Assignment and Assumption with respect to such assignment is delivered to the

Administrative Agent) shall not be less than $5,000,000 unless each of the Borrower and the Administrative Agent otherwise consent to a lesser amount, provided that no such consent of the Borrower shall be required if an Event of Default has occurred and is continuing;

(B) each partial assignment shall be made as an assignment of a proportionate part of all the assigning Lender's rights and obligations under this Agreement, provided that this clause shall not be construed to prohibit the assignment of a proportionate part of all the assigning Lender's rights and obligations in respect of one Class of Commitments or Loans;

(C) the parties to each assignment shall execute and deliver to the Administrative Agent (x) an Assignment and Assumption or (y) to the extent applicable, an agreement incorporating an Assignment and Assumption by reference pursuant to an Approved Electronic Platform as to which the Administrative Agent and the parties to the Assignment and Assumption are participants, together with a processing and recordation fee of $3,500, such fee to be paid by either the assigning Lender or the assignee Lender or shared between such Lenders; and

(D) the assignee, if it shall not be a Lender, shall deliver to the Administrative Agent an Administrative Questionnaire in which the assignee designates one or more credit contacts to whom all syndicate-level information (which may contain material non-public information about the Borrower and its Affiliates and their Related Parties or their respective securities) will be made available and who may receive such information in accordance with the assignee's compliance procedures and applicable laws, including Federal and state securities laws.

For the purposes of this Section 9.04(b), the terms "Approved Fund" and "Ineligible Institution" have the following meanings:

"Approved Fund" means any Person (other than a natural person) that is engaged in making, purchasing, holding or investing in bank loans and similar extensions of credit in the ordinary course of its business and that is administered or managed by (a) a Lender, (b) an Affiliate of a Lender or (c) an entity or an Affiliate of an entity that administers or manages a Lender.

"Ineligible Institution" means (a) a natural person, (b) a Defaulting Lender or its Lender Parent, (c) a holding company, investment vehicle or trust for, or owned and operated for the primary benefit of, a natural person or relative(s) thereof or (d) the Borrower or any of its Affiliates; provided that, with respect to clause (c), such holding company, investment vehicle or trust shall not constitute an Ineligible Institution if it (x) has not been established for the primary purpose of acquiring any Loans or Commitments, (y) is managed by a professional advisor, who is not such natural person or a relative thereof, having significant experience in the business of making or purchasing commercial loans, and (z) has assets greater than $25,000,000 and a significant part of its activities consist of making or purchasing commercial loans and similar extensions of credit in the ordinary course of its business.

(iii) Subject to acceptance and recording thereof pursuant to paragraph (b)(iv) of this Section, from and after the effective date specified in each Assignment and Assumption the assignee thereunder shall be a party hereto and, to the extent of the interest assigned by such Assignment and Assumption, have the rights and obligations of a Lender under this Agreement, and the assigning Lender thereunder shall, to the extent of the interest assigned by such Assignment and Assumption, be released from its obligations under this Agreement (and, in the case of an Assignment and Assumption covering all of the assigning Lender's rights and obligations under this Agreement, such Lender shall cease to be a party hereto but shall continue to be entitled to the benefits of Sections 2.15, 2.16, 2.17 and 9.03). Any assignment or transfer by a Lender of rights or obligations under this Agreement that does not comply with this Section 9.04 shall be treated for purposes of this Agreement as a sale by such Lender of a participation in such rights and obligations in accordance with paragraph (c) of this Section.

(iv) The Administrative Agent, acting for this purpose as a non-fiduciary agent of the Borrower, shall maintain at one of its offices a copy of each Assignment and Assumption delivered to it and a register for the recordation of the names and addresses of the Lenders, and the Commitment of, and principal amount (and stated interest) of the Loans and LC Disbursements owing to, each Lender pursuant to the terms hereof from time to time (the "Register"). The entries in the Register shall be conclusive, and the Borrower, the Administrative Agent, the Issuing Banks and the Lenders shall treat each Person whose name is recorded in the Register pursuant to the terms hereof as a Lender hereunder for all purposes of this Agreement, notwithstanding notice to the contrary. The Register shall be available for inspection by the Borrower, any Issuing Bank and any Lender, at any reasonable time and from time to time upon reasonable prior notice.

(v) Upon its receipt of (x) a duly completed Assignment and Assumption executed by an assigning Lender and an assignee or (y) to the extent applicable, an agreement incorporating an Assignment and Assumption by reference pursuant to an Approved Electronic Platform as to which the Administrative Agent and the parties to the Assignment and Assumption are participants, the assignee's completed Administrative Questionnaire (unless the assignee shall already be a Lender hereunder), the processing and recordation fee referred to in paragraph (b) of this Section and any written consent to such assignment required by paragraph (b) of this Section, the Administrative Agent shall accept such Assignment and Assumption and record the information contained therein in the Register; provided that if either the assigning Lender or the assignee shall have failed to make any payment required to be made by it pursuant to Section 2.05(c), 2.06(d) or (e), 2.07(b), 2.18(e) or 9.03(c), the Administrative Agent shall have no obligation to accept such Assignment and Assumption and record the information therein in the Register unless and until such payment shall have been made in full, together with all accrued interest thereon. No assignment shall be effective for purposes of this Agreement unless it has been recorded in the Register as provided in this paragraph.

(c) Any Lender may, without the consent of, or notice to, the Borrower, the Administrative Agent, the Issuing Banks or the Swingline Lender, sell participations to one or more banks or other entities (a "Participant"), other than an Ineligible Institution, in all or a portion of such Lender's rights and/or obligations under this Agreement (including all or a portion of its Commitment and/or the Loans owing to it); provided that (A) such Lender's obligations under this Agreement shall remain unchanged; (B) such Lender shall remain solely responsible to the other parties hereto for the performance of such obligations; and (C) the Borrower, the Administrative Agent, the Issuing Banks and the other Lenders shall continue to deal solely and directly with such Lender in connection with such Lender's rights and obligations under this Agreement. Any agreement or instrument pursuant to which a Lender sells such a participation shall provide that such Lender shall retain the sole right to enforce this Agreement and to approve any amendment, modification or waiver of any provision of this Agreement; provided that such agreement or instrument may provide that such Lender will not, without the consent of the Participant, agree to any amendment, modification or waiver described in the first proviso to Section 9.02(b) that affects such Participant. The Borrower agrees that each Participant shall be entitled to the benefits of Sections 2.15, 2.16 and 2.17 (subject to the requirements and limitations therein, including the requirements under Section 2.17(f) (it being understood that the documentation required under Section 2.17(f) shall be delivered to the participating Lender)) to the same extent as if it were a Lender and had acquired its interest by assignment pursuant to paragraph (b) of this Section; provided that such Participant (A) agrees to be subject to the provisions of Sections 2.18 and 2.19 as if it were an assignee under paragraph (b) of this Section; and (B) shall not be entitled to receive any greater payment under Sections 2.15 or 2.17, with respect to any participation, than its participating Lender would have been entitled to receive, except to the extent such entitlement to receive a greater payment results from a Change in Law that occurs after the Participant acquired the applicable participation. Each Lender that sells a participation agrees, at the Borrower's request and expense, to use reasonable efforts to cooperate with the Borrower to effectuate the provisions of Section 2.19(b) with respect to any Participant. To the extent permitted by law, each Participant also shall be entitled to the benefits of Section 9.08 as though it were a Lender, provided that such Participant agrees to be subject to Section 2.18(c) as though it were a Lender. Each Lender that sells a participation shall, acting solely for this purpose as a non-fiduciary agent of the Borrower, maintain a register on which it enters the name and address of each Participant and the principal amounts (and stated interest) of each Participant's interest in the Loans or other obligations under the Loan Documents (the "Participant Register"); provided that no Lender shall have any obligation to disclose all or any portion of the Participant Register (including the identity of any Participant or any information relating to a Participant's interest in any Commitments, Loans, Letters of Credit or its other obligations under any Loan Document) to any Person except to the extent that such disclosure is necessary to establish that such Commitment, Loan, Letter of Credit or other obligation is in registered form under Section 5f.103-1(c) of the United States Treasury Regulations. The entries in the Participant Register shall be conclusive absent manifest error, and such Lender shall treat each Person whose name is recorded in the Participant Register as the owner of such participation for all purposes of this Agreement notwithstanding any notice to the contrary. For the avoidance of doubt, the Administrative Agent (in its capacity as Administrative Agent) shall have no responsibility for maintaining a Participant Register.

(d) Any Lender may at any time pledge or assign a security interest in all or any portion of its rights under this Agreement to secure obligations of such Lender, including any pledge or assignment to secure obligations to a Federal Reserve Bank, and this Section shall not apply to any such pledge or assignment of a security interest; provided that no such pledge or assignment of a security interest shall release a Lender from any of its obligations hereunder or substitute any such pledgee or assignee for such Lender as a party hereto.

SECTION 9.05 Survival. All covenants, agreements, representations and warranties made by the Borrower in the Loan Documents and in the certificates or other instruments delivered in connection with or pursuant to this Agreement or any other Loan Document shall be considered to have been relied upon by the other parties hereto and shall survive the execution and delivery of the Loan Documents and the making of any Loans and issuance of any Letters of Credit, regardless of any investigation made by any such other party or on its behalf and notwithstanding that the Administrative Agent, any Issuing Bank or any Lender may have had notice or knowledge of any Default or incorrect representation or warranty at the time any credit is extended hereunder, and shall continue in full force and effect as long as the principal of or any accrued interest on any Loan or any fee or any other amount payable under this Agreement or any other Loan Document is outstanding and unpaid or any Letter of Credit is outstanding and so long as the Commitments have not expired or terminated. The provisions of Sections 2.15, 2.16, 2.17 and 9.03 and Article VIII shall survive and remain in full force and effect regardless of the consummation of the transactions contemplated hereby, the repayment of the Loans, the expiration or termination of the Letters of Credit and the Commitments or the termination of this Agreement or any other Loan Document or any provision hereof or thereof.

SECTION 9.06 Counterparts; Integration; Effectiveness; Electronic Execution. (a) This Agreement may be executed in counterparts (and by different parties hereto on different counterparts), each of which shall constitute an original, but all of which when taken together shall constitute a single contract. This Agreement, the other Loan Documents and any separate letter agreements with respect to (i) fees payable to the Administrative Agent and (ii) the reductions of the Letter of Credit Commitment of any Issuing Bank constitute the entire contract among the parties relating to the subject matter hereof and supersede any and all previous agreements and understandings, oral or written, relating to the subject matter hereof. Except as provided in Section 4.01, this Agreement shall become effective when it shall have been executed by the Administrative Agent and when the Administrative Agent shall have received counterparts hereof which, when taken together, bear the signatures of each of the other parties hereto, and thereafter shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns.

(b) Delivery of an executed counterpart of a signature page of (x) this Agreement, (y) any other Loan Document and/or (z) any document, amendment, approval, consent, information, notice (including, for the avoidance of doubt, any notice delivered pursuant to Section 9.01), certificate, request, statement, disclosure or authorization related to this Agreement, any other Loan Document and/or the transactions contemplated hereby and/or thereby (each an "Ancillary Document") that is an Electronic Signature transmitted by telecopy, emailed pdf. or any other electronic means that reproduces an image of an actual executed signature page shall be effective as delivery of a manually executed counterpart of this Agreement, such other Loan Document or such Ancillary Document, as applicable. The words "execution," "signed," "signature," "delivery," and words of like import in or relating to this Agreement, any other Loan Document and/or any Ancillary Document shall be deemed to include Electronic Signatures, deliveries or the keeping of records in any electronic form (including deliveries by telecopy, emailed pdf. or any other electronic means that reproduces an image of an actual executed signature page), each of which shall be of the same legal effect, validity or enforceability as a manually executed signature, physical delivery thereof or the use of a paper-based recordkeeping system, as the case may be; provided that nothing herein shall require the Administrative Agent to accept Electronic Signatures in any form or format without its prior written consent and pursuant to procedures approved by it; provided, further, without limiting the foregoing, (i) to the extent the Administrative Agent has agreed to accept any Electronic Signature, the Administrative Agent and each of the Lenders shall be entitled to rely on such Electronic Signature purportedly given by or on behalf of the Borrower without further verification thereof and without any obligation to review the appearance or form of any such Electronic signature and (ii) upon the request of the Administrative Agent or any Lender, any Electronic Signature shall be promptly followed by a manually executed counterpart. Without limiting the generality of the foregoing, the Borrower hereby (i) agrees that, for all purposes, including without limitation, in connection with any workout, restructuring, enforcement of remedies, bankruptcy proceedings or litigation among the Administrative Agent, the Lenders and the Borrower, Electronic Signatures transmitted by telecopy, emailed pdf. or any other electronic means that reproduces an image of an actual executed signature page and/or any electronic images of this Agreement, any other Loan Document and/or any Ancillary Document shall have the same legal effect, validity and enforceability as any paper original, (ii) the Administrative Agent and each of the Lenders may, at its option, create one or more copies of this Agreement, any other Loan Document and/or any Ancillary Document in the form of an imaged electronic record in any format, which shall be deemed created in the ordinary course of such Person's business, and destroy the original paper document (and all such electronic records shall be considered an original for all purposes and shall have the same legal effect, validity and enforceability as a paper record), (iii) waives any argument, defense or right to contest the legal effect, validity or enforceability of this Agreement, any other Loan Document and/or any Ancillary Document based solely on the lack of paper original copies of this Agreement, such other Loan Document and/or such Ancillary Document, respectively, including with respect to any signature pages thereto and (iv) waives any claim against any Lender-Related Person for any Liabilities arising solely from the Administrative Agent's and/or any Lender's reliance on or use of Electronic Signatures and/or transmissions by telecopy, emailed pdf. or any other electronic means that reproduces an image of an actual executed signature page, including any Liabilities arising as a result of the failure of the Borrower to use any available security measures in connection with the execution, delivery or transmission of any Electronic Signature.

SECTION 9.07 Severability. Any provision of any Loan Document held to be invalid, illegal or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such invalidity, illegality or unenforceability without affecting the validity, legality and enforceability of the remaining provisions thereof; and the invalidity of a particular provision in a particular jurisdiction shall not invalidate such provision in any other jurisdiction.

SECTION 9.08 Right of Setoff. If an Event of Default shall have occurred and be continuing, each Lender, each Issuing Bank, and each of their respective Affiliates is hereby authorized at any time and from time to time, to the fullest extent permitted by law, to set off and apply any and all deposits (general or special, time or demand, provisional or final and in whatever currency denominated) at any time held, and other obligations at any time owing, by such Lender, such Issuing Bank or any such Affiliate, to or for the credit or the account of the Borrower against any and all of the Obligations now or hereafter existing under this Agreement or any other Loan Document to such Lender or such Issuing Bank or their respective Affiliates, irrespective of whether or not such Lender, Issuing Bank or Affiliate shall have made any demand under this Agreement or any other Loan Document and although such obligations may be contingent or unmatured or are owed to a branch office or Affiliate of such Lender or such Issuing Bank different from the branch office or Affiliate holding such deposit or obligated on such indebtedness; provided that in the event that any Defaulting Lender shall exercise any such right of setoff, (x) all amounts so set off shall be paid over immediately to the Administrative Agent for further application in accordance with the provisions of Section 2.21 and, pending such payment, shall be segregated by such Defaulting Lender from its other funds and deemed held in trust for the benefit of the Administrative Agent, the Issuing Banks, and the Lenders, and (y) the Defaulting Lender shall provide promptly to the Administrative Agent a statement describing in reasonable detail the Obligations owing to such Defaulting Lender as to which it exercised such right of setoff. The rights of each Lender, each Issuing Bank and their respective Affiliates under this Section are in addition to other rights and remedies (including other rights of setoff) that such Lender, such Issuing Bank or their respective Affiliates may have. Each Lender and Issuing Bank agrees to notify the Borrower and the Administrative Agent promptly after any such setoff and application; provided that the failure to give such notice shall not affect the validity of such setoff and application.

SECTION 9.09 Governing Law; Jurisdiction; Consent to Service of Process. (a) This Agreement and the other Loan Documents shall be construed in accordance with and governed by the law of the State of New York.

(b) Each of the Lenders and the Administrative Agent hereby irrevocably and unconditionally agrees that, notwithstanding the governing law provisions of any applicable Loan Document, any claims brought against the Administrative Agent by any Lender relating to this Agreement, any other Loan Document or the consummation or administration of the transactions contemplated hereby or thereby shall be construed in accordance with and governed by the law of the State of New York.

(c) Each of the parties hereto hereby irrevocably and unconditionally submits, for itself and its property, to the exclusive jurisdiction of the United States District Court for the Southern District of New York sitting in the Borough of Manhattan (or if such court lacks subject matter jurisdiction, the Supreme Court of the State of New York sitting in the Borough of Manhattan), and any appellate court from any thereof, in any action or proceeding arising out of or relating to this Agreement or any other Loan Document or the transactions relating hereto or thereto, or for recognition or enforcement of any judgment, and each of the parties hereto hereby irrevocably and unconditionally agrees that all claims in respect of any such action or proceeding may (and any such claims brought against the Administrative Agent or any of its Related Parties may only) be heard and determined in such Federal (to the extent permitted by law) or New York State court. Each of the parties hereto agrees that a final judgment in any such action or proceeding shall be conclusive and may be enforced in other jurisdictions by suit on the judgment or in any other manner provided by law. Nothing in this Agreement or in any other Loan Document shall affect any right that the Administrative Agent, any Issuing Bank or any Lender may otherwise have to bring any action or proceeding relating to this Agreement against the Borrower, the Borrower or its properties in the courts of any jurisdiction.

(d) Each of the parties hereto hereby irrevocably and unconditionally waives, to the fullest extent it may legally and effectively do so, any objection which it may now or hereafter have to the laying of venue of any suit, action or proceeding arising out of or relating to this Agreement or any other Loan Document in any court referred to in paragraph (c) of this Section. Each of the parties hereto hereby irrevocably waives, to the fullest extent permitted by law, the defense of an inconvenient forum to the maintenance of such action or proceeding in any such court.

(e) Each party to this Agreement irrevocably consents to service of process in the manner provided for notices in Section 9.01. Nothing in this Agreement or any other Loan Document will affect the right of any party to this Agreement to serve process in any other manner permitted by law.

SECTION 9.10 WAIVER OF JURY TRIAL. EACH PARTY HERETO HEREBY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN ANY LEGAL PROCEEDING DIRECTLY OR INDIRECTLY ARISING OUT OF OR RELATING TO THIS AGREEMENT, ANY OTHER LOAN DOCUMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY OR THEREBY (WHETHER BASED ON CONTRACT, TORT OR ANY OTHER THEORY). EACH PARTY HERETO (A) CERTIFIES THAT NO REPRESENTATIVE, AGENT OR ATTORNEY OF ANY OTHER PARTY HAS REPRESENTED, EXPRESSLY OR OTHERWISE, THAT SUCH OTHER PARTY WOULD NOT, IN THE EVENT OF LITIGATION, SEEK TO ENFORCE THE FOREGOING WAIVER AND (B) ACKNOWLEDGES THAT IT AND THE OTHER PARTIES HERETO HAVE BEEN INDUCED TO ENTER INTO THIS AGREEMENT BY, AMONG OTHER THINGS, THE MUTUAL WAIVERS AND CERTIFICATIONS IN THIS SECTION.

SECTION 9.11 Headings. Article and Section headings and the Table of Contents used herein are for convenience of reference only, are not part of this Agreement and shall not affect the construction of, or be taken into consideration in interpreting, this Agreement.

SECTION 9.12 Confidentiality. Each of the Administrative Agent, the Issuing Banks and the Lenders agrees to maintain the confidentiality of the Information (as defined below), except that Information may be disclosed (a) to its and its Affiliates' directors, officers, employees and agents, including accountants, legal counsel and other advisors (it being understood that the Persons to whom such disclosure is made will be informed of the confidential nature of such Information and instructed to keep such Information confidential), (b) to the extent requested by any Governmental Authority (including any self-regulatory authority, such as the National Association of Insurance Commissioners), (c) to the extent required by applicable laws or regulations or by any subpoena or similar legal process, (d) to any other party to this Agreement, (e) in connection with the exercise of any remedies under this Agreement or any other Loan Document or any suit, action or proceeding relating to this Agreement or any other Loan Document or the enforcement of rights hereunder or thereunder, (f) subject to an agreement containing provisions substantially the same as those of this Section, to (1) any assignee of or Participant in, or any prospective assignee of or Participant in, any of its rights or obligations under this Agreement or (2) any actual or prospective counterparty (or its advisors) to any swap or derivative transaction relating to the Borrower and its obligations, (g) on a confidential basis to (1) any rating agency in connection with rating the Borrower or its Subsidiaries or the credit facilities provided for herein or (2) the CUSIP Service Bureau or any similar agency in connection with the issuance and monitoring of identification numbers with respect to the credit facilities provided for herein, (h) with the consent of the Borrower or (i) to the extent such Information (1) becomes publicly available other than as a result of a breach of this Section or (2) becomes available to the Administrative Agent, any Issuing Bank or any Lender on a nonconfidential basis from a source other than the Borrower. For the purposes of this Section, "Information" means all information received from the Borrower relating to the Borrower or its business, other than any such information that is available to the Administrative Agent, any Issuing Bank or any Lender on a nonconfidential basis prior to disclosure by the Borrower and other than information pertaining to this Agreement routinely provided by arrangers to data service providers, including league table providers, that serve the lending industry; provided that, in the case of information received from the Borrower after the date hereof, such information is clearly identified at the time of delivery as confidential. Any Person required to maintain the confidentiality of Information as provided in this Section shall be considered to have complied with its obligation to do so if such Person has exercised the same degree of care to maintain the confidentiality of such Information as such Person would accord to its own confidential information.

SECTION 9.13 Material Non-Public Information. (a) **EACH LENDER ACKNOWLEDGES THAT INFORMATION AS DEFINED IN SECTION 9.12 FURNISHED TO IT PURSUANT TO THIS AGREEMENT MAY INCLUDE MATERIAL NON-PUBLIC INFORMATION CONCERNING THE BORROWER AND ITS RELATED PARTIES OR THEIR RESPECTIVE SECURITIES, AND CONFIRMS THAT IT HAS DEVELOPED COMPLIANCE PROCEDURES REGARDING THE USE OF MATERIAL NON-PUBLIC INFORMATION AND THAT IT WILL HANDLE SUCH MATERIAL NON-PUBLIC INFORMATION IN ACCORDANCE WITH THOSE PROCEDURES AND APPLICABLE LAW, INCLUDING FEDERAL AND STATE SECURITIES LAWS**.

(b) **ALL INFORMATION, INCLUDING REQUESTS FOR WAIVERS AND AMENDMENTS, FURNISHED BY THE BORROWER OR THE ADMINISTRATIVE AGENT PURSUANT TO, OR IN THE COURSE OF ADMINISTERING, THIS AGREEMENT WILL BE SYNDICATE-LEVEL INFORMATION, WHICH MAY CONTAIN MATERIAL NON-PUBLIC INFORMATION ABOUT THE BORROWER AND ITS RELATED PARTIES OR ITS RESPECTIVE SECURITIES. ACCORDINGLY, EACH LENDER REPRESENTS TO THE BORROWER AND THE ADMINISTRATIVE AGENT THAT IT HAS IDENTIFIED IN ITS ADMINISTRATIVE QUESTIONNAIRE A CREDIT CONTACT WHO MAY RECEIVE INFORMATION THAT MAY CONTAIN MATERIAL NON-PUBLIC INFORMATION IN ACCORDANCE WITH ITS COMPLIANCE PROCEDURES AND APPLICABLE LAW.**

SECTION 9.14 USA PATRIOT Act. Each Lender that is subject to the requirements of the USA PATRIOT Act of 2001 (the "Patriot Act") hereby notifies the Borrower that pursuant to the requirements of the Patriot Act, it is required to obtain, verify and record information that identifies the Borrower, which information includes the name and address of the Borrower and other information that will allow such Lender to identify the Borrower in accordance with the Patriot Act.

SECTION 9.15 Intentionally Omitted.

SECTION 9.16 Interest Rate Limitation. Notwithstanding anything herein to the contrary, if at any time the interest rate applicable to any Loan, together with all fees, charges and other amounts which are treated as interest on such Loan under applicable law (collectively the "Charges"), shall exceed the maximum lawful rate (the "Maximum Rate") which may be contracted for, charged, taken, received or reserved by the Lender holding such Loan in accordance with applicable law, the rate of interest payable in respect of such Loan hereunder, together with all Charges payable in respect thereof, shall be limited to the Maximum Rate and, to the extent lawful, the interest and Charges that would have been payable in respect of such Loan but were not payable as a result of the operation of this Section shall be cumulated and the interest and Charges payable to such Lender in respect of other Loans or periods shall be increased (but not above the Maximum Rate therefor) until such cumulated amount, together with interest thereon at the NYFRB Rate to the date of repayment, shall have been received by such Lender.

SECTION 9.17 No Fiduciary Duty, etc. The Borrower acknowledges and agrees, and acknowledges its Subsidiaries' understanding, that no Credit Party will have any obligations except those obligations expressly set forth herein and in the other Loan Documents and each Credit Party is acting solely in the capacity of an arm's length contractual counterparty to the Borrower with respect to the Loan Documents and the transactions contemplated therein and not as a financial advisor or a fiduciary to, or an agent of, the Borrower or any other person. The Borrower agrees that it will not assert any claim against any Credit Party based on an alleged breach of fiduciary duty by such Credit Party in connection with this Agreement and the transactions contemplated hereby. Additionally, the Borrower acknowledges and agrees that no Credit Party is advising the Borrower as to any legal, tax, investment, accounting, regulatory or any other matters in any jurisdiction. The Borrower shall consult with its own advisors concerning such matters and shall be responsible for making its own independent investigation and appraisal of the transactions contemplated hereby, and the Credit Parties shall have no responsibility or liability to the Borrower with respect thereto.

The Borrower further acknowledges and agrees, and acknowledges its Subsidiaries' understanding, that each Credit Party, together with its Affiliates, is a full service securities or banking firm engaged in securities trading and brokerage activities as well as providing investment banking and other financial services. In the ordinary course of business, any Credit Party may provide investment banking and other financial services to, and/or acquire, hold or sell, for its own accounts and the accounts of customers, equity, debt and other securities and financial instruments (including bank loans and other obligations) of, the Borrower and other companies with which it may have commercial or other relationships. With respect to any securities and/or financial instruments so held by any Credit Party or any of its customers, all rights in respect of such securities and financial instruments, including any voting rights, will be exercised by the holder of the rights, in its sole discretion.

In addition, the Borrower acknowledges and agrees, and acknowledges its Subsidiaries' understanding, that each Credit Party and its affiliates may be providing debt financing, equity capital or other services (including financial advisory services) to other companies in respect of which the Borrower or its Subsidiaries may have conflicting interests regarding the transactions described herein and otherwise. No Credit Party will use confidential information obtained from the Borrower by virtue of the transactions contemplated by the Loan Documents or its other relationships with the Borrower in connection with the performance by such Credit Party of services for other companies, and no Credit Party will furnish any such information to other companies. The Borrower also acknowledges that no Credit Party has any obligation to use in connection with the transactions contemplated by the Loan Documents, or to furnish to the Borrower, confidential information obtained from other companies.

SECTION 9.18 Acknowledgment and Consent to Bail-In of Affected Financial Institutions. Notwithstanding anything to the contrary in any Loan Document or in any other agreement, arrangement or understanding among any such parties, each party hereto acknowledges that any liability of any Affected Financial Institution arising under any Loan Document may be subject to the Write-Down and Conversion Powers of the applicable Resolution Authority and agrees and consents to, and acknowledges and agrees to be bound by:

(a) the application of any Write-Down and Conversion Powers by the applicable Resolution Authority to any such liabilities arising hereunder which may be payable to it by any party hereto that is an Affected Financial Institution; and

(b) the effects of any Bail-In Action on any such liability, including, if applicable:

(i) a reduction in full or in part or cancellation of any such liability;

(ii) a conversion of all, or a portion of, such liability into shares or other instruments of ownership in such Affected Financial Institution, its parent entity, or a bridge institution that may be issued to it or otherwise conferred on it, and that such shares or other instruments of ownership will be accepted by it in lieu of any rights with respect to any such liability under this Agreement or any other Loan Document; or

(iii) the variation of the terms of such liability in connection with the exercise of the Write-Down and Conversion Powers of the applicable Resolution Authority.

[Signature Pages on file with the Administrative Agent]

EXHIBIT F-1

FORM OF BORROWING REQUEST

JPMorgan Chase Bank, N.A.,
as Administrative Agent
for the Lenders referred to below

131 South Dearborn, Floor 04
Chicago, Illinois 60603-5506
Attention: Kathryn V Tyler
Facsimile: (844) 490-5663
Email Address: katy.tyler@chase.com

Re: Northwest Natural Gas Company

[Date]

Ladies and Gentlemen:

Reference is hereby made to the Amended and Restated Credit Agreement dated as of November 3, 2021 (as the same may be amended, restated, supplemented or otherwise modified from time to time, the "Credit Agreement"), among Northwest Natural Gas Company (the "Borrower"), the Lenders from time to time party thereto and JPMorgan Chase Bank, N.A., as administrative agent (in such capacity, the "Administrative Agent"). Capitalized terms used but not defined herein shall have the meanings assigned to such terms in the Credit Agreement. The Borrower hereby gives you notice pursuant to Section 2.03 of the Credit Agreement that it requests a Borrowing under the Credit Agreement, and in that connection the Borrower specifies the following information with respect to such Borrowing requested hereby:

1. Aggregate principal amount of Borrowing:[1] __________
2. Date of Borrowing (which shall be a Business Day)[2]: __________
3. Type of Borrowing[3]: __________
4. Interest Period and the last day thereof (if a Term Benchmark Borrowing):[4] __________
5. Location and number of the Borrower's account or any other account agreed upon by the Administrative Agent and the Borrower to which proceeds of Borrowing are to be disbursed: __________

[Signature Page Follows]

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[1] Not less than applicable amounts specified in Section 2.02(c).

[2] For RFR Loans based on Daily Simple SOFR, the date should be 5 Business Days after the date of the Borrowing Request.

[3] Specify ABR Borrowing, Term Benchmark Borrowing or RFR Borrowing. If no election as to the Type of Borrowing specified, then the requested Borrowing shall be an ABR Borrowing.

[4] Which must comply with the definition of "Interest Period" and end not later than the Maturity Date.

The undersigned hereby represents and warrants that the conditions to lending specified in Section 4.02 of the Credit Agreement are satisfied as of the date hereof.

Very truly yours,

NORTHWEST NATURAL GAS
COMPANY,

as Borrower

By: ______________________________
Name:
Title:

EXHIBIT F-2

FORM OF INTEREST ELECTION REQUEST

JPMorgan Chase Bank, N.A.,
as Administrative Agent
for the Lenders referred to below

131 South Dearborn, Floor 04
Chicago, Illinois 60603-5663
Attention: Kathryn V Tyler
Facsimile: (844) 490-5663

Email Address: katy.tyler@chase.com

Re: Northwest Natural Gas Company

[Date]

Ladies and Gentlemen:

Reference is hereby made to the Amended and Restated Credit Agreement dated as of November 3, 2021 (as the same may be amended, restated, supplemented or otherwise modified from time to time, the "Credit Agreement"), among Northwest Natural Gas Company (the "Borrower"), the Lenders from time to time party thereto and JPMorgan Chase Bank, N.A., as administrative agent (in such capacity, the "Administrative Agent"). Capitalized terms used but not defined herein shall have the meanings assigned to such terms in the Credit Agreement. The Borrower hereby gives you notice pursuant to Section 2.08 of the Credit Agreement that it requests to [convert][continue] an existing Borrowing under the Credit Agreement, and in that connection the Borrower specifies the following information with respect to such [conversion][continuation] requested hereby:

1. List date, Type, principal amount and Interest Period (if applicable) of existing Borrowing: __________
2. Aggregate principal amount of resulting Borrowing: __________
3. Effective date of interest election (which shall be a Business Day): __________
4. Type of Borrowing (ABR or Term Benchmark): __________
5. Interest Period and the last day thereof (if a Term Benchmark Borrowing):[5] __________

[Signature Page Follows]

[5] Which must comply with the definition of "Interest Period" and end not later than the Maturity Date.

Very truly yours,

NORTHWEST NATURAL GAS
COMPANY,

as Borrower

By: ______________________________
Name:
Title:

February 23, 2023

[Name]
[Address]
[City, State Zip]

Re: Amended and Restated Change in Control Severance Agreement

Dear [Name]:

Northwest Natural Gas Company, an Oregon corporation (the "Company"), a wholly-owned subsidiary of Northwest Natural Holding Company, an Oregon corporation ("Parent"), considers the establishment and maintenance of a sound and vital management to be essential to protecting and enhancing the best interests of the Company. In this connection, the Company recognizes that, as is the case with many publicly held corporations like Parent, the possibility of a change in control may exist and that such possibility, and the uncertainty and questions which it may raise among management, may result in the departure or distraction of management personnel to the detriment of the Company, its customers and its shareholders. Accordingly, the Board of Directors of the Company (the "Board") has determined that appropriate steps should be taken to reinforce and encourage the continued attention and dedication of members of the Company's management to their assigned duties without distraction in circumstances arising from the possibility of a change in control of Parent or the Company.

In order to induce you to remain in the employ of the Company, this letter agreement, which has been approved by the Board, sets forth severance benefits which the Company agrees will be provided to you in the event your employment with the Company is terminated in connection with a Change in Control (as defined in Section 3 hereof) under the circumstances described below. The Company and you have entered into a prior letter agreement regarding change in control severance benefits dated October 1, 2018. Upon your signature of this letter agreement, that prior agreement as amended by the letter agreement between you and the Company dated February 27, 2020, shall be amended and restated in its entirety in the form of this agreement.

1. Agreement to Provide Services; Right to Terminate.

(i) Except as otherwise provided in paragraph (ii) below, the Company or you may terminate your employment at any time, subject to the Company's providing the benefits hereinafter specified in accordance with the terms hereof.

(ii) In the event of a Potential Change in Control (as defined in Section 3 hereof), you agree that you will not leave the employ of the Company (other than as a result of Disability, as such term is hereinafter defined) and will render the services contemplated in the recitals to this Agreement until the earliest of (a) a date which is 270 days from the occurrence of such Potential Change in Control, or (b) a termination of your employment pursuant to which you become entitled under this Agreement to receive the benefits provided in Section 5(iii) below.

2. Term of Agreement. This Agreement shall commence on the date hereof and shall continue in effect until December 31, 2023; provided, however, that commencing on January 1, 2024 and each January 1 thereafter, the term of this Agreement shall automatically be extended for one additional year unless at least 90 days prior to such January 1 date, the Company or you shall have given notice that this Agreement shall not be extended (provided that no such notice may be given by the Company during the pendency of a Potential Change in Control); and provided, further, that this Agreement shall continue in effect for a period of twenty-four (24) months beyond the term provided herein if a Change in Control shall have occurred during such term. Notwithstanding anything in this Section 2 to the contrary, this Agreement shall terminate automatically if you or the Company terminate your employment prior to the earlier of Shareholder Approval (as defined in Section 3 hereof), if applicable, or the Change in Control. In addition, the Company may terminate this Agreement during your employment if, prior to the earlier of Shareholder Approval, if applicable, or the Change in Control, you cease to hold your current position with the Company, except by reason of a promotion.

3. Change in Control; Potential Change in Control; Shareholder Approval; Person.

(i) For purposes of this Agreement, a "Change in Control" shall mean the occurrence of any of the following events:

(A) The consummation of:

(1) any consolidation, merger or plan of share exchange involving Parent (a "Merger") as a result of which the holders of outstanding securities of Parent ordinarily having the right to vote for the election of directors ("Voting Securities") immediately prior to the Merger do not continue to hold at least 50% of the combined voting power of the outstanding Voting Securities of the surviving corporation or a parent corporation of the surviving corporation immediately after the Merger, disregarding any Voting Securities issued to or retained by such holders in respect of securities of any other party to the Merger;

(2) any consolidation, merger, plan of share exchange or other transaction involving the Company as a result of which Parent does not continue to hold, directly or indirectly, at least 50% of the outstanding securities of the Company ordinarily having the right to vote for the election of directors; or

(3) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all, or substantially all, the assets of Parent or the Company;

(B) At any time during a period of two consecutive years, individuals who at the beginning of such period constituted the board of directors of Parent ("Incumbent Directors") shall cease for any reason to constitute at least a majority thereof; provided, however, that the term "Incumbent Director" shall also include each new director elected during such two-year period whose nomination or election was approved by two-thirds of the Incumbent Directors then in office; or

(C) Any Person (as hereinafter defined) shall, as a result of a tender or exchange offer, open market purchases or privately negotiated purchases from anyone other than Parent, have become the beneficial owner (within the meaning of Rule 13d-3 under the Securities Exchange Act of 1934), directly or indirectly, of Voting Securities representing twenty percent (20%) or more of the combined voting power of the then outstanding Voting Securities, but disregarding any Voting Securities with respect to which that acquirer has filed SEC Schedule 13G indicating that the Voting Securities were not acquired and are not held for the purpose of or with the effect of changing or influencing, directly or indirectly, the Company's management or policies, unless and until that entity or person files SEC Schedule 13D, at which point this exception will not apply to such Voting Securities, including those previously subject to a SEC Schedule 13G filing.

Notwithstanding anything in the foregoing to the contrary, unless otherwise determined by the Board, no Change in Control shall be deemed to have occurred for purposes of this Agreement if (1) you acquire (other than on the same basis as all other holders of shares of Common Stock of Parent or the Company) an equity interest in an entity that acquires Parent or the Company in a Change in Control otherwise described under subparagraph (A) above, or (2) you are part of a group that constitutes a Person which becomes a beneficial owner of Voting Securities in a transaction that otherwise would have resulted in a Change in Control under subparagraph (C) above.

(ii) For purposes of this Agreement, a "Potential Change in Control" shall be deemed to have occurred if:

(A) Parent or the Company enters into an agreement, the consummation of which would result in the occurrence of a Change in Control;

(B) any Person (including Parent or the Company) publicly announces an intention to take or to consider taking actions which if consummated would constitute a Change in Control; or

(C) the Board adopts a resolution to the effect that, for purposes of this Agreement, a Potential Change in Control has occurred.

(iii) For purposes of this Agreement, "Shareholder Approval" shall be deemed to have occurred if the shareholders of Parent approve an agreement entered into by Parent, the consummation of which would result in the occurrence of a Change in Control.

(iv) For purposes of this Agreement, the term "Person" shall mean and include any individual, corporation, partnership, group, association or other "person," as such term is used in Section 14(d) of the Securities Exchange Act of 1934 (the "Exchange Act"), other than Parent or the Company or any employee benefit plan sponsored by Parent or the Company.

4. Termination Following Shareholder Approval or Change in Control. If a Change in Control occurs, you shall be entitled to the benefits provided in Section 5(iii) hereof in the event that (x) a Date of Termination (as defined in Section 4(v) below) of your employment with the Company occurred or occurs after the earlier of Shareholder Approval, if applicable, or the Change in Control and no later than twenty-four (24) months after the Change in Control, or (y) your employment with the Company is terminated by you for Good Reason (as defined below)

based on an event occurring concurrent with or subsequent to the earlier of Shareholder Approval, if applicable, or the Change in Control and your Notice of Termination (as defined in Section 4(iv) below) in connection therewith shall have been given no later than twenty-four (24) months after the Change in Control; provided, however, that if any such termination is (a) because of your death, (b) by the Company for Cause (as defined below) or Disability, or (c) by you other than for Good Reason based on an event occurring concurrent with or subsequent to the earlier of Shareholder Approval, if applicable, or the Change in Control, then you shall not be entitled to the benefits provided in Section 5(iii) hereof.

(i) Disability. Termination by the Company of your employment based on "Disability" shall mean termination because of your absence from your duties with the Company on a full-time basis for one hundred eighty (180) consecutive days as a result of your incapacity due to physical or mental illness, unless within thirty (30) days after Notice of Termination is given to you following such absence you shall have returned to the full-time performance of your duties.

(ii) Cause. Termination by the Company of your employment for "Cause" shall mean termination upon (a) the willful and continued failure by you to perform substantially your assigned duties with the Company (other than any such failure resulting from your incapacity due to physical or mental illness) after a demand for substantial performance is delivered to you by the Chair of the Board or Chief Executive Officer of the Company which specifically identifies the manner in which such executive believes that you have not substantially performed your duties or (b) the willful engaging by you in illegal conduct which is materially and demonstrably injurious to the Company. For purposes of this paragraph (ii), no act, or failure to act, on your part shall be considered "willful" unless done, or omitted to be done, by you in knowing bad faith and without reasonable belief that your action or omission was in, or not opposed to, the best interests of the Company. Any act, or failure to act, based upon authority given pursuant to a resolution duly adopted by the Board or based upon the advice of counsel for the Company shall be conclusively presumed to be done, or omitted to be done, by you in good faith and in the best interests of the Company. Notwithstanding the foregoing, you shall not be deemed to have been terminated for Cause unless and until there shall have been delivered to you a copy of a resolution duly adopted by the affirmative vote of not less than three-quarters of the entire membership of the Board at a meeting of the Board called and held for the purpose (after reasonable notice to you and an opportunity for you, together with your counsel, to be heard before the Board), finding that in the good faith opinion of the Board you were guilty of the conduct set forth above in (a) or (b) of this paragraph (ii) and specifying the particulars thereof in detail.

(iii) Good Reason. Termination by you of your employment with the Company for "Good Reason" shall mean termination by you of your employment with the Company based on any of the following events provided you give Notice of Termination after the occurrence of any of the following events and no later than 30 days after the later of (1) notice to you of such event, or (2) the Change in Control:

(A) a change in your status, title, position(s) or responsibilities as an officer of the Company which does not represent a promotion from your status, title, position(s) and responsibilities as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control, or the assignment to you of any duties or responsibilities which are inconsistent with such status, title or position(s), or any removal of you from or any failure to reappoint or reelect you to such position(s), except in connection with the termination of your employment for Cause or Disability or as a result of your death or by you other than for Good Reason; provided that, for the avoidance of doubt, if you are an officer of the Company or its affiliate and subject to the reporting requirements of Section 16 of the Securities Exchange Act of 1934, as amended (the "Exchange Act") with respect to those entities immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control, then being an officer of the surviving entity or its parent who is not subject to the reporting requirements of Section 16 of the Exchange Act of 1934 shall be deemed an adverse change to your status and responsibilities;

(B) a reduction by the Company in your base salary as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control;

(C) the failure by the Company or Parent, as applicable, to continue in effect any Plan (as hereinafter defined) in which you are participating immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control (or Plans providing you with at least substantially similar benefits) other than as a result of the normal expiration of any such Plan in accordance with its terms as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control, or the taking of any action, or the failure to act, by the Company or Parent which would adversely affect your continued participation in any of such Plans on at least as favorable a basis to you as is the case immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control or which would materially reduce your benefits in the future under any of such Plans or deprive you of any material benefit enjoyed by you immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control; provided that, for the avoidance of doubt, (1) if a Plan provides for payments to you after the termination of the Plan in accordance with its terms, any changes to the payments to be made to you under such Plan after its termination will be deemed a failure to continue such Plan in accordance with its terms, and (2) the failure to adopt a new annual incentive plan after the expiration of an annual incentive plan will be deemed to be the failure to continue in effect a Plan, even though the prior plan expired in accordance with its terms;

(D) the failure by the Company to (x) provide and credit you with the number of paid vacation days to which you are then entitled in accordance with the Company's normal vacation policy as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control or (y) to implement and honor a new vacation policy on substantially the same terms as the Company's vacation policy as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control;

(E) the Company's requiring you to be based more than 25 miles from where your office is located immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control except for required travel on the Company's business to an extent substantially consistent with the business travel obligations which you undertook on behalf of the Company prior to the earlier of Shareholder Approval, if applicable, or the Change in Control;

(F) the failure by the Company to obtain from any Successor (as hereinafter defined) the assent to this Agreement contemplated by Section 7 hereof;

(G) any purported termination by the Company of your employment which is not effected pursuant to a Notice of Termination satisfying the requirements of paragraph (iv) below (and, if applicable, paragraph (ii) above); and for purposes of this Agreement, no such purported termination shall be effective; or

(H) the failure by the Company to pay you any portion of your current compensation, to credit your account under any deferred compensation plan in accordance with your previous election, or to pay you any portion of an installment of deferred compensation under any Plan in which you participated, within seven (7) days of the date such compensation is due.

For purposes of this Agreement, "Plan" shall mean any compensation plan such as an incentive, stock option or restricted stock plan or any employee benefit plan such as a savings, pension, profit sharing, deferred compensation, medical, disability, accident, life insurance, or relocation plan or policy or any other plan, program or policy of the Company or Parent intended to benefit employees of the Company.

(iv) Notice of Termination. Any purported termination by the Company or by you (other than termination due to your death, which shall terminate your employment automatically) following the earlier of Shareholder Approval, if applicable, or a Change in Control shall be communicated by Notice of Termination to the other party hereto. For purposes of this Agreement, a "Notice of Termination" shall mean a notice which shall indicate the specific termination provision in this Agreement relied upon and shall set forth in reasonable detail the facts and circumstances claimed to provide a basis for termination of your employment under the provision so indicated.

(A) With respect to any Notice of Termination given by you for Good Reason, such Notice of Termination may indicate that such termination for Good Reason shall be conditioned upon, and postponed until, the date on which it is finally determined, either by mutual written agreement of the parties or by the arbitrators in a proceeding as provided in Section 13 hereof, that Good Reason exists for such termination. If a Notice of Termination given by you for Good Reason indicates that such termination shall be so conditioned and postponed, then, if the Company disputes the existence of Good Reason, the Company shall, within thirty (30) days after the Notice of Termination is given, notify you that a dispute exists concerning the termination, whereupon Section 13 hereof shall apply to such dispute. If no such notice is given by the Company within such 30-day period, then a final determination that Good Reason exists shall be deemed to have occurred on the date thirty (30) days after the Notice of Termination for Good Reason is given.

(B) Notwithstanding anything to the contrary in this Agreement:

(1) if, at any time before the Date of Termination determined pursuant to this Agreement with respect to any purported termination by you of your employment with the Company, there exists a basis for the Company to terminate your employment for Cause, then the Company may, regardless of whether or not you have given Notice of Termination for Good Reason and regardless of whether or not Good Reason exists, terminate your employment for Cause, in which event you shall not be entitled to the benefits provided in Section 5(iii) hereof, and

(2) if you die or your employment is terminated based on Disability after you have given Notice of Termination for Good Reason and before the Date of Termination determined under this Agreement with respect to that Notice of Termination, and it is subsequently finally determined that Good Reason existed at the time your employment terminated, then termination of your employment shall be deemed to have occurred for Good Reason (and not due to your death or Disability) and you shall be entitled to the benefits provided in Section 5(iii) hereof.

(v) Date of Termination. "Date of Termination" shall mean the date your employment with the Company is terminated following the earlier of Shareholder Approval, if applicable, or a Change in Control, which date shall be determined as follows:

(A) if your employment is to be terminated for Disability, thirty (30) days after Notice of Termination is given (provided that, if you shall have returned to the performance of your duties on a full-time basis during such thirty (30) day period, then the termination for Disability contemplated by the Notice of Termination shall not occur),

(B) if your employment is terminated due to your death, the date of your death,

(C) if your employment is to be terminated by the Company other than for Disability, or if your employment is to be terminated by you without a claim of Good Reason, the date specified in the Notice of Termination, and

(D) if your employment is to be terminated by you for Good Reason, the date ninety (90) days after the date on which a Notice of Termination is given, unless either:

(1) an earlier date has been agreed to by the Company either in advance of, or after, receiving such Notice of Termination (in which case such earlier date shall be the Date of Termination),

(2) pursuant to and in accordance with Section 4(iv) you have indicated in your Notice of Termination that you are conditioning your termination upon (and postponing such termination until) the date on which it is finally determined that Good Reason exists for such termination (in which case the later of such date as determined in accordance with Section 4(iv) above, or the date otherwise determined under this Section 4(v)(D), shall be the Date of Termination),

(3) the Company shall not have notified you within fifteen (15) days after a Notice of Termination for Good Reason is given that it intends to fully correct the circumstances giving rise to Good Reason (in which case the date fifteen (15) days after the Notice of Termination shall be the Date of Termination), or

(4) if the Company gives notice as provided in Section 4(v)(D)(3) and if the circumstances giving rise to Good Reason are fully corrected on or prior to the date that is ninety (90) days after such Notice of Termination was given, then

the termination for Good Reason contemplated by such Notice of Termination shall not occur.

(E) You shall not be obligated to perform any services after the Date of Termination that would prevent the termination of your employment on such Date of Termination from qualifying as a "separation from service" as defined in Treasury Regulations §1.409A-1(h).

5. Compensation Upon Termination or During Disability.

(i) During any period following the earlier of Shareholder Approval, if applicable, or a Change in Control that you fail to perform your duties as a result of incapacity due to physical or mental illness, you shall continue to receive your full base salary at the rate then in effect and any benefits or awards under any Plans shall continue to accrue during such period, to the extent not inconsistent with such Plans, until your employment is terminated pursuant to and in accordance with Sections 4(i) and 4(v) hereof. Thereafter, your benefits shall be determined in accordance with the Plans then in effect.

(ii) If your employment shall be terminated for Cause or as a result of death following the earlier of Shareholder Approval, if applicable, or a Change in Control, the Company shall pay you your full base salary through the Date of Termination at the rate in effect just prior to the time a Notice of Termination is given plus any benefits or awards which pursuant to the terms of any Plans have been earned or become payable, but which have not yet been paid to you. Thereupon the Company shall have no further obligations to you under this Agreement.

(iii) If a Change in Control occurs and either (a) after the earlier of Shareholder Approval, if applicable, or the Change in Control and no later than twenty-four (24) months after the Change in Control, a Date of Termination of your employment with the Company occurred or occurs as a result of a termination by the Company other than for Cause or Disability, or (b) your employment with the Company is terminated by you for Good Reason based on an event occurring concurrent with or subsequent to the earlier of Shareholder Approval, if applicable, or the Change in Control and your Notice of Termination in connection therewith shall have been given no later than twenty-four (24) months after the Change in Control, then, by no later than the fifth day following the later of the Date of Termination or the Change in Control (except as may otherwise be provided), you shall be entitled, without regard to any contrary provisions of any Plan, to a severance benefit as follows:

(A) the Company shall pay your full base salary through the Date of Termination at the rate in effect just prior to the time a Notice of Termination is given plus any benefits or awards which pursuant to the terms of any Plans have been earned or become payable, but which have not yet been paid to you; provided, however, that with respect to a termination of your employment for Good Reason based on a reduction by the Company in your base salary as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control, the Company shall pay your full base salary through the Date of Termination at the rate in effect just prior to such reduction plus any benefits or awards which pursuant to the terms of any Plans have been earned or become payable, but which have not yet been paid to you;

(B) as severance pay and in lieu of any further salary for periods subsequent to the Date of Termination, the Company shall pay to you in a single payment an amount in cash equal to two and a half (2.5) times the sum of (1) the greater of (i) your annual rate of base salary in effect on the Date of Termination or (ii) your annual rate of base salary in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control and (2) the your target annual bonus in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control;

(C) if you hold an equity award which vested upon consummation of the Change of Control on a prorated basis, the Company shall pay you an amount equal to (1) the amount you would have received if such award had fully vested (or vested at target performance) upon the consummation of the Change of Control minus (2) the amount paid to you with respect to such award based on the prorated vesting (without taking into account any tax withholding); and

(D) for a thirty (30) month period after the Date of Termination (specifically including a Date of Termination that occurs after Shareholder Approval and prior to a Change in Control), the Company shall arrange to provide you, your spouse and your dependents with life, accident and health insurance benefits substantially similar to those which you were receiving immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control. Such benefits may take the form, at the Company's discretion, of the Company's payment of COBRA or other premiums for you, your spouse and your dependents continued coverage under the Company's group health plan and other insurance programs (if you, your spouse and your dependents are eligible for continuation coverage under the Company's group health plan and other insurance programs), payment of the premium for individual medical insurance policies and life and accident policies selected by you for you, your spouse and your dependents, or a combination of the foregoing.

Notwithstanding the foregoing, the Company shall not provide any benefit otherwise receivable by you pursuant to this subparagraph (C) to the extent that a similar benefit is actually received by you from a subsequent employer during such thirty (30) month period, and any such benefit actually received by you shall be reported to the Company.

(iv) The amount of any payment provided for in this Section 5 shall not be reduced, offset or subject to recovery by the Company by reason of any compensation earned by you as the result of employment by another employer after the Date of Termination, or otherwise. Your entitlements under Section 5(iii) are in addition to, and not in lieu of, any rights, benefits or entitlements you may have under the terms or provisions of any Plan.

6. Parachute Payments. Notwithstanding any other provision in this Agreement or any other agreement or arrangement between the Company or Parent and you with respect to compensation or benefits (each an "Other Arrangement"), in the event that the provisions of Sections 280G and 4999 of the Internal Revenue Code of 1986, as amended, or any successor provisions (the "Code"), would cause you to receive a greater after-tax benefit from the Capped Benefit (as defined below) than from the amounts (including the monetary value of any non-cash benefits) otherwise payable pursuant to this Agreement or any Other Arrangement (the "Specified Benefits"), the Capped Benefit shall be paid to you in lieu of the Specified Benefits. The "Capped Benefit" shall equal the Specified Benefits, reduced by the amount necessary to prevent any portion of the Specified Benefits from being a "parachute payment" as defined in Section 280G(b)(2) of the Code. The Capped Benefit would therefore equal 2.99 multiplied by

your applicable "base amount" as defined in Section 280G(b)(3) of the Code. For purposes of determining whether you would receive a greater after-tax benefit from the Capped Benefit than from the Specified Benefits, there shall be taken into account any excise tax that would be imposed under Section 4999 of the Code and all federal, state and local taxes required to be paid by you in respect of the receipt of such payments. The parties acknowledge that the application of Section 280G is uncertain in many respects and agree that the Company shall make all calculations and determinations under this section (including application and interpretation of the Code and related regulatory, administrative and judicial authorities) in good faith, which calculations and determinations shall be conclusive absent manifest error. The Company shall provide you with a reasonable opportunity to review and comment on the Company's calculations of the Capped Benefit and to request which of the Specified Benefits shall be reduced. If, after payment of any amount under this Agreement or any Other Arrangement, it is determined that the calculation of the Capped Benefit was calculated incorrectly, the amount of the Capped Benefit will be adjusted, the Company shall pay to you any additional amount that should have been paid to you, and you shall repay to the Company any amount that should not have been paid to you, in each case with interest at the discount rate applicable under Section 280G(d)(4) of the Code.

7. Successors; Binding Agreement.

(i) Upon your written request, the Company will seek to have any Successor (as hereinafter defined), by agreement in form and substance satisfactory to you, assent to the fulfillment by the Company of its obligations under this Agreement. For purposes of this Agreement, "Successor" shall mean any Person that succeeds to, or has the practical ability to control (either immediately or with the passage of time), the Company's business directly, by merger, consolidation or purchase of assets, or indirectly, by purchase of Parent's or the Company's Voting Securities or otherwise.

(ii) This Agreement shall inure to the benefit of and be enforceable by your personal or legal representatives, executors, administrators, successors, heirs, distributees, devisees and legatees. If you should die while any amount would still be payable to you hereunder if you had continued to live, all such amounts, unless otherwise provided herein, shall be paid in accordance with the terms of this Agreement to your devisee, legatee or other designee or, if there be no such designee, to your estate.

8. Fees and Expenses. The Company shall pay to you all legal fees and related expenses incurred by you in good faith as a result of (i) your termination following the earlier of Shareholder Approval, if applicable, or a Change in Control (including all such fees and expenses, if any, incurred in contesting or disputing in good faith any such termination) or (ii) your seeking to obtain or enforce in good faith any right or benefit provided by this Agreement.

9. Survival. The respective obligations of, and benefits afforded to, the Company and you as provided in Sections 5, 6, 7(ii), 8 and 13 of this Agreement shall survive termination of this Agreement, but only with respect to a Change in Control occurring during the term of this Agreement.

10. Notice. For the purposes of this Agreement, notices and all other communications provided for in this Agreement shall be in writing and shall be deemed to have been duly given when delivered or mailed by United States registered mail, return receipt requested, postage prepaid and addressed to the address of the respective party set forth on the first page of this

Agreement, provided that all notices to the Company shall be directed to the attention of the Chair of the Board or Chief Executive Officer of the Company, with a copy to the Secretary of the Company, or to such other address as either party may have furnished to the other in writing in accordance herewith, except that notice of change of address shall be effective only upon receipt.

11. Miscellaneous. No provision of this Agreement may be modified, waived or discharged unless such modification, waiver or discharge is agreed to in a writing signed by you and the Chair of the Board or Chief Executive Officer of the Company. No waiver by either party hereto at any time of any breach by the other party hereto of, or of compliance with, any condition or provision of this Agreement to be performed by such other party shall be deemed a waiver of similar or dissimilar provisions or conditions at the same or at any prior or subsequent time. No agreements or representations, oral or otherwise, express or implied, with respect to the subject matter hereof have been made by either party which are not expressly set forth in this Agreement. The validity, interpretation, construction and performance of this Agreement shall be governed by the laws of the State of Oregon.

12. Validity. The invalidity or unenforceability of any provision of this Agreement shall not affect the validity or enforceability of any other provision of this Agreement, which shall remain in full force and effect.

13. Arbitration. Any dispute or controversy arising under or in connection with this Agreement shall be settled exclusively by arbitration in Portland, Oregon by three arbitrators in accordance with the rules of the American Arbitration Association then in effect. Judgment may be entered on the arbitrators' award, which award shall be a final and binding determination of the dispute or controversy, in any court having jurisdiction; provided, however, that you shall be entitled to seek specific performance of your right to be paid until the Date of Termination during the pendency of any dispute or controversy arising under or in connection with this Agreement. The Company shall bear all costs and expenses of the arbitrators arising in connection with any arbitration proceeding pursuant to this Section 13.

14. Related Agreements. To the extent that any provision of any other agreement between the Company or any of its subsidiaries and you shall limit, qualify or be inconsistent with any provision of this Agreement, then for purposes of this Agreement, while the same shall remain in force, the provision of this Agreement shall control and such provision of such other agreement shall be deemed to have been superseded, and to be of no force or effect, as if such other agreement had been formally amended to the extent necessary to accomplish such purpose.

15. Section 409A.

(i) The intent of the parties is that payments and benefits under this Agreement comply with Section 409A of the Internal Revenue Code of 1986, as amended, and the regulations and guidance promulgated thereunder ("Section 409A"), to the extent subject thereto, or otherwise be exempt from Section 409A, and accordingly, to the maximum extent permitted, this Agreement shall be interpreted and administered to be exempt from or in compliance therewith. Each amount to be paid or benefit to be provided under this Agreement shall be construed as a separate and distinct payment for purposes of Section 409A. Without limiting the foregoing and notwithstanding anything contained herein to the contrary, to the extent required to avoid accelerated taxation and/or tax penalties under Section 409A:

(a) You shall not be considered to have terminated employment with the Company for purposes of any payments under this Agreement which are subject to Section 409A until you would be considered to have incurred a "separation from service" from the Company within the meaning of Section 409A;

(b) Amounts that would otherwise be payable and benefits that would otherwise be provided pursuant to this Agreement or any other arrangement between you and the Company during the six (6) month period immediately following your separation from service shall instead be paid on the first business day after the date that is six (6) months following your separation from service (or, if earlier, your date of death);

(c) Omitted

(d) Any payment that will be in compliance with Section 409A only if payable upon a change in control event within the meaning Treas. Reg. Section 1.409A-3(i)(5) shall be made only in compliance with such regulation; and

(e) If any severance amount payable under this Agreement or any other agreement that you may have a right or entitlement to as of the date of this Agreement constitutes deferred compensation under Section 409A, then the portion of the benefits payable hereunder equal to such other amount shall instead be provided in the form set forth in this Agreement or such other agreement.

(ii) The Company makes no representation that any or all of the payments described in this Agreement will be exempt from or comply with Section 409A and makes no undertaking to preclude Section 409A from applying to any such payment. You understand and agree that you shall be solely responsible for the payment of any taxes, penalties, interest or other expenses incurred by you on account of non-compliance with Section 409A.

16. Counterparts. This Agreement may be executed in several counterparts, each of which shall be deemed to be an original, but all of which together will constitute one and the same instrument.

If this letter correctly sets forth our agreement on the subject matter hereof, kindly sign and return to the Company the enclosed copy of this letter which will then constitute our agreement on this subject.

Sincerely,

NORTHWEST NATURAL GAS COMPANY

By: ______________________________________
Melinda Rogers
VP, Chief HR and Diversity Officer

Agreed to this ____ day
of ____________, 2023.

____
David H. Anderson

RESTRICTED STOCK UNIT AWARD AGREEMENT

This Agreement is entered into as of February __, 2023, between Northwest Natural Holding Company, an Oregon corporation (the "Company"), and ____________ ("Recipient").

On February 22, 2023, the Organization and Executive Compensation Committee (the "Committee") of the Company's Board of Directors (the "Board") awarded restricted stock units to Recipient pursuant to Section 6 of the Company's Long Term Incentive Plan (the "Plan"). Recipient desires to accept the award subject to the terms and conditions of this Agreement.

NOW, THEREFORE, the parties agree as follows:

1. Grant of Restricted Stock Units; Dividend Equivalents.

Subject to the terms and conditions of this Agreement, the Company hereby grants to the Recipient _________ restricted stock units (the "RSUs"). The grant of RSUs obligates the Company, upon vesting in accordance with this Agreement, to deliver to the Recipient one share of Common Stock of the Company (a "Share") for each RSU. Upon vesting of each RSU, the Company also agrees to make a dividend equivalent cash payment with respect to each vested RSU in an amount equal to the total amount of dividends paid per share of Company Common Stock for which the dividend record dates occurred after the date of this Agreement and before the date of delivery of the underlying Shares. The RSUs are subject to forfeiture as set forth in Sections 2.1 and 2.10 below.

2. Vesting; Forfeiture Restriction.

2.1 Vesting Schedule.

(a) All of the RSUs shall initially be unvested. Subject to Sections 2.3, 2.4, 2.5, 2.10 and 5.2, the RSUs shall vest as follows:

(1) one-fourth of the RSUs shall vest on March 1, 2024 if the Performance Threshold (as defined in Section 2.2 below) is satisfied for 2023;

(2) an additional one-fourth of the RSUs shall vest on March 1, 2025 if the Performance Threshold is satisfied for 2024;

(3) an additional one-fourth of the RSUs shall vest on March 1, 2026 if the Performance Threshold is satisfied for 2025; and

(4) the final one-fourth of the RSUs shall vest on March 1, 2027 if the Performance Threshold is satisfied for 2026.

(b) If the Performance Threshold is not satisfied for any year set forth in (1), (2), (3) or (4) above, the RSUs that would have vested if the Performance Threshold had been satisfied for that year (the "Performance Year") shall be forfeited to the Company effective as of the last day of the Performance Year. For example, if the Performance Threshold is not satisfied for 2023, all RSUs that were scheduled to vest on March 1, 2024 shall be forfeited effective as of December 31, 2023.

(c) If a Change in Control (as defined in Section 2.6 below) occurs, the Performance Threshold shall be deemed to be satisfied for all Performance Years that were not completed prior to the Change in Control, with the effect that the RSUs outstanding at the time of the Change of Control shall vest upon completion of the applicable time periods in Section 2.1(a).

2.2 Performance Threshold.

(a) For purposes of this Agreement, the "Performance Threshold" for any year shall be satisfied if the ROE (as defined below) for that year is greater than the 5 Yr Avg Cost of LT Debt (as defined below) for that year.

(b) The "ROE" for any year shall be calculated by dividing the Company's Adjusted Net Income (as defined below) for the year by the Average Equity (as defined below) for the year. Subject to adjustment in accordance with Section 2.2(c) below, the Company's "Adjusted Net Income" for any year shall be equal to the Company's net income attributable to common shareholders for the year, as set forth in the audited consolidated statement of income of the Company and its subsidiaries for the year. Subject to adjustment in accordance with Section 2.2(c) below, "Average Equity" for any year shall mean the average of the Company's total common stock equity as of the last day of the year and the Company's total common stock equity as of the last day of the prior year, in each case as set forth on the audited consolidated balance sheet of the Company and its subsidiaries as of the applicable date.

(c) The Committee may, at any time, approve adjustments to the calculation of ROE to take into account such unanticipated circumstances or significant, non-recurring or unplanned events as the Committee may determine in its sole discretion, and such adjustments may increase or decrease ROE. Possible circumstances that may be the basis for adjustments shall include, but not be limited to, any change in applicable accounting rules or principles; any gain or loss on the disposition of a business; impairment of assets; dilution caused by Board approved business acquisition; tax changes and tax impacts of other changes; changes in applicable laws and regulations; changes in rate case timing; changes in the Company's structure; and any other circumstances outside of management's control.

(d) The "5 Yr Avg Cost of LT Debt" for any year shall mean the average of five numbers consisting of the Avg Cost of LT Debt (as defined below) for that year and for each of the four preceding years. The "Avg Cost of LT Debt" for any year shall be equal to the sum of the Weighted Costs (as defined below) calculated for each series or tranche of long-term debt of the Company outstanding on the last day of the year. The "Weighted Cost" for a series or tranche of long-term debt as of any date shall be calculated by multiplying the Effective Interest Rate (as defined below) on the debt as of that date by the outstanding principal balance of the debt on that date, and then dividing the resulting amount by the Company's total outstanding principal balance of long-term debt as of that date. The "Effective Interest Rate" for a series or tranche of long-term debt as of any date shall be the yield calculated based on the settlement date for the original issuance of the series or tranche, the maturity date of the series or tranche, the stated annual interest rate of the series or tranche in effect on that date, the number of interest payments per year under the terms of the series or tranche, the initial borrowing of an amount equal to the principal balance net of Debt Issuance Costs (as defined below) for the series or tranche, and the repayment of principal at maturity or otherwise according to the terms of the series or tranche. The "Debt Issuance Costs" for a series or tranche of long-term debt shall include the fees, commissions and expenses of issuance of such debt, any other purchase discount from the face amount of such debt, and any premiums, write-offs of unamortized debt issuance costs and other costs incurred in connection with retiring debt refinanced with the proceeds of such debt, all as reflected in the Company's accounting records. For purposes of this Section 2.2(d), the Company's long term debt and the interest rates and outstanding principal balances of the outstanding series or tranches of long-term debt as of any date shall be those amounts as set forth in the audited consolidated financial statements of the Company and its subsidiaries for the year ending on that date, and shall in all cases include the current portion of any long-term debt and exclude borrowings under a revolving credit facility. For the avoidance of doubt, the Effective Interest Rate for purposes of this Agreement of each series of fixed-rate long-term debt outstanding as of the date of this Agreement is set forth on Exhibit A hereto.

2.3 Effect of Retirement, Death, or Disability.

(a) If Recipient's employment by the Company or any parent or subsidiary of the Company (the "Employer") terminates because of Retirement (as defined below), death or physical disability (within the meaning of Section 22(e)(3) of the Internal Revenue Code of 1986, as amended, and the regulations and guidance promulgated thereunder ("Code") and a Change in Control has not previously occurred, all outstanding RSUs shall remain outstanding and subject to potential future vesting upon satisfaction of the Performance Threshold for the applicable years.

(b) If Recipient's employment by the Employer terminates because of Retirement, death or physical disability and a Change in Control subsequently occurs, all outstanding RSUs shall immediately vest. If a Change in Control occurs and Recipient's employment by the Employer subsequently terminates because of Retirement, death or physical disability, all outstanding RSUs shall immediately vest.

(c) The term "Retirement" means termination of employment (1) on or after the first anniversary of the date of this Agreement, and (2) after the Recipient is (i) age 62 with at least five years of service as an employee of the Company or a parent or subsidiary of the Company, or (ii) age 55 with age plus years of service (including fractions) as an employee of the Company or a parent or subsidiary of the Company totaling at least 70; provided, however, that a termination of Recipient's employment by the Employer for Cause (as defined in Section 2.8 below) shall not constitute a Retirement.

2.4 CIC Acceleration if Party to a Severance Agreement. If Recipient is a party to a Change in Control Severance Agreement with the Company or a parent or subsidiary of the Company, all outstanding RSUs shall immediately vest if Recipient becomes entitled to a Change in Control Severance Benefit (as defined below). A "Change in Control Severance Benefit" means the severance benefit provided for in Recipient's Change in Control Severance Agreement with the Company or a parent or subsidiary of the Company; provided, however, that such severance benefit is a "Change in Control Severance Benefit" for purposes of this Agreement only if, under the terms of Recipient's Change in Control Severance Agreement, Recipient becomes entitled to the severance benefit (a) after a change in control of the Company has occurred, (b) because Recipient's employment with the Employer has been terminated by Recipient for good reason in accordance with the terms and conditions of the Change in Control Severance Agreement or by the Employer other than for cause, and (c) because Recipient has satisfied any other conditions or requirements specified in the Change in Control Severance Agreement and necessary for Recipient to become entitled to receive the severance benefit. For purposes of this Section 2.4, the terms "change in control," "good reason," "cause" and "disability" shall have the meanings set forth in Recipient's Change in Control Severance Agreement.

2.5 CIC Acceleration if Not a Party to a Severance Agreement. If Recipient is not a party to a Change in Control Severance Agreement with the Company or a parent or subsidiary of the Company, all outstanding RSUs shall immediately vest if a Change in Control (as defined in Section 2.6 below) occurs and at any time after the earlier of Shareholder Approval (as defined in Section 2.7 below), if any, or the Change in Control and on or before the second anniversary of the Change in Control, (a) Recipient's employment is terminated by the Employer (or its successor) without Cause (as defined in Section 2.8 below), or (b) Recipient's employment is terminated by Recipient for Good Reason (as defined in Section 2.9 below).

2.6 Change in Control. For purposes of this Agreement, a "Change in Control" of the Company shall mean the occurrence of any of the following events:

(a) The consummation of:

(1) any consolidation, merger or plan of share exchange involving the Company (a "Merger") as a result of which the holders of outstanding securities of the Company ordinarily having the right to vote for the election of directors ("Voting Securities") immediately prior to the Merger do not continue to hold at least 50% of the combined voting power of the outstanding Voting Securities of the surviving corporation or a parent corporation of the surviving corporation immediately after the Merger, disregarding any Voting Securities issued to or retained by such holders in respect of securities of any other party to the Merger; or

(2) any consolidation, merger, plan of share exchange or other transaction involving Northwest Natural Gas Company ("NW Natural") as a result of which the Company does not continue to hold, directly or indirectly, at least 50% of the outstanding securities of NW Natural ordinarily having the right to vote for the election of directors; or

(3) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all, or substantially all, the assets of the Company or NW Natural;

(b) At any time during a period of two consecutive years, individuals who at the beginning of such period constituted the Board ("Incumbent Directors") shall cease for any reason to constitute at least a majority thereof; provided, however, that the term "Incumbent Director" shall also include each new director elected during such two-year period whose nomination or election was approved by two-thirds of the Incumbent Directors then in office; or

(c)Any person (as such term is used in Section 14(d) of the Securities Exchange Act of 1934, other than the Company or any employee benefit plan sponsored by the Company or NW Natural) shall, as a result of a tender or exchange offer, open market purchases or privately negotiated purchases from anyone other than the Company, have become the beneficial owner (within the meaning of Rule 13d-3 under the Securities Exchange Act of 1934), directly or indirectly, of Voting Securities representing twenty percent (20%) or more of the combined voting power of the then outstanding Voting Securities, but disregarding any Voting Securities with respect to which that acquirer has filed SEC Schedule 13G indicating that the Voting Securities were not acquired and are not held for the purpose of or with the effect of changing or influencing, directly or indirectly, the Company's management or policies, unless and until that entity or person files SEC Schedule 13D, at which point this exception will not apply to such Voting Securities, including those previously subject to a SEC Schedule 13G filing.

2.7 Shareholder Approval. For purposes of this Agreement, "Shareholder Approval" shall be deemed to have occurred if the shareholders of the Company approve an agreement entered into by the Company, the consummation of which would result in the occurrence of a Change in Control.

2.8 Cause. For purposes of this Agreement, "Cause" shall mean (a) the willful and continued failure by Recipient to perform substantially Recipient's assigned duties with the Employer (other than any such failure resulting from incapacity due to physical or mental illness) after a demand for substantial performance is delivered to Recipient by the Employer which specifically identifies the manner in which Recipient has not substantially performed such duties, (b) willful commission by Recipient of an act of fraud or dishonesty resulting in economic or financial injury to the Company or Employer, (c) willful misconduct by Recipient that substantially impairs the business or reputation of the Company or Employer, or (d) willful gross negligence by Recipient in the performance of his or her duties.

2.9 Good Reason. For purposes of this Agreement, "Good Reason" shall mean the occurrence after Shareholder Approval, if applicable, or the Change in Control, of any of the following circumstances, but only if (x) Recipient gives notice to Employer of Recipient's intent to terminate employment for Good Reason within 30 days after the later of (1) notice to Recipient of such circumstances, or (2) the Change in Control, and (y) such circumstances are not fully corrected by the Employer within 90 days after Recipient's notice:

(a) the assignment to Recipient of a different title, job or responsibilities that results in a decrease in the level of Recipient's responsibility; provided that Good Reason shall not exist if Recipient continues to have the same or a greater general level of responsibility for the former Employer operations after the Change in Control as Recipient had prior to the Change in Control even though such responsibilities have necessarily changed due to the former Employer operations becoming a subsidiary or division of the surviving company;

(b) a reduction by the Employer in Recipient's base salary as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control;

(c) the failure by Employer to continue in effect any employee benefit or incentive plan in which Recipient is participating immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control (or plans providing Recipient with at least substantially similar benefits) other than as a result of the normal expiration of any such plan in accordance with its terms as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control, or the taking of any action, or the failure to act, by Employer which would adversely affect Recipient's continued participation in any of such plans on at least as favorable a basis to Recipient as is the case immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control or which would materially reduce Recipient's benefits in the future under any of such plans or deprive Recipient of any material benefit enjoyed by Recipient immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control;

(d) the failure by the Employer to provide and credit Recipient with the number of paid vacation days to which Recipient is then entitled in accordance with the Employer's normal vacation policy as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control; or

(e) the Employer's requiring Recipient to be based more than 25 miles from where Recipient's office is located immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control except for required travel on the Employer's business to an extent substantially consistent with the business travel obligations which Recipient undertook on behalf of the Employer prior to the earlier of Shareholder Approval, if applicable, or the Change in Control.

2.10 Forfeiture; Possible Restoration. If Recipient ceases to be employed by the Employer for any reason or for no reason, with or without cause, other than because of Retirement, death or physical disability (within the meaning of Section 22(e)(3) of the Code), any RSUs that did not vest pursuant to this Section 2 or Section 5.2 at or prior to the time of such termination of employment shall be forfeited to the Company; provided, however, that if Recipient's employment is terminated by the Employer without Cause or by the Recipient for Good Reason after Shareholder Approval but before a Change in Control, any RSUs that are forfeited under this sentence shall be restored to the Recipient and vested if a Change in Control subsequently occurs within two years.

3. Certification and Delivery.

As soon as practicable following the completion of each Performance Year, the Company shall calculate the ROE and the 5 Yr Avg Cost of LT Debt for that Performance Year, and shall submit those calculations to the Committee. At or prior to the regularly scheduled meeting of the Committee held in February of the year immediately following each Performance Year (each, a "Certification Meeting"), the Committee shall certify in writing (which may consist of approved minutes of the meeting) whether or not the Performance Threshold was satisfied for that Performance Year. Unless otherwise required under this Agreement as a result of the occurrence of a Change in Control, no amounts shall be delivered or paid unless the Committee certifies that the Performance Threshold has been satisfied for the applicable Performance Year. Subject to applicable tax withholding, on a date (a "Payment Date") that is on or as soon as practicable after the date any of the RSUs become vested or, if later, five business days following the Certification Meeting relating to those RSUs, the Company shall deliver to Recipient (a) the number of Shares underlying the RSUs that vested (rounded down to the nearest whole share), and (b) the dividend equivalent cash payment determined under Section 1 with respect to the number of Shares that are delivered; provided, however, that if accelerated vesting of the RSUs occurs pursuant to Section 2.3(b) as a result of Recipient's Retirement after a Change in Control has previously occurred, the Payment Date shall be payable upon Recipient's separation from service (within the meaning of Section 409A of the Internal Revenue Code). Notwithstanding the foregoing provisions of this Section 3, if Recipient shall have made a valid election to defer receipt of the Shares and dividend equivalent cash payment pursuant to the terms of Northwest Natural's Deferred Compensation Plan for Directors and Executives (the "DCP"), payment of RSUs that vest shall be made in accordance with that election.

4. Tax Withholding.

4.1 Recipient acknowledges that, on any Payment Date when Shares are delivered to Recipient, the Value (as defined below) on that date of the Shares so delivered (as well as the amount of the related dividend equivalent cash payment) will be treated as ordinary compensation income for federal and state income and FICA tax purposes, and that the Employer will be required to withhold taxes on these income amounts. To satisfy the required withholding amount, the Employer shall first withhold all or part of the dividend equivalent cash payment, and if that is insufficient, the Employer shall withhold the number of Shares having a Value equal to the remaining withholding amount. For purposes of this Section 4, the "Value" of a Share shall be equal to the closing market price for Company Common Stock on the last trading day preceding the date on which the Share is treated for federal income tax purposes as transferred to Recipient.

4.2 If the Employer is required to withhold FICA taxes with respect to the RSUs prior to the time the shares underlying the RSU otherwise become payable, Recipient shall, immediately upon notification of the amount due, pay to the Company in cash or by check amounts necessary to satisfy applicable FICA withholding requirements. If Recipient fails to pay the amount demanded, the Company may withhold that amount from other amounts payable to Recipient, including salary, subject to applicable law. Alternatively, the Employer may, in its sole discretion, choose to treat the FICA withholding as a loan to Recipient on terms determined by the Employer and communicated to Recipient.

4.3 Notwithstanding Section 4.1., Recipient may elect not to have Shares withheld to cover taxes by giving notice to the Company in writing prior to the Payment Date, in which case the Shares shall be issued or acquired in Recipient's name on the Payment Date thereby triggering the tax consequences, but the Company shall retain the certificate for the Shares as security until Recipient shall have paid to the Company in cash any required tax withholding not covered by withholding of the dividend equivalent cash payment.

5. Sale of the Company.

If there shall occur a merger, consolidation or plan of exchange involving the Company pursuant to which the outstanding shares of Common Stock of the Company are converted into cash or other stock, securities or property, or a sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all, or substantially all, the assets of the Company, then either:

5.1 the unvested RSUs shall be converted into restricted stock units for stock of the surviving or acquiring corporation in the applicable transaction, using the exchange rate, if any, used in determining shares of the surviving corporation to be held by the former holders of the Company's Common Stock following the applicable transaction, or, if there was no exchange rate, taking into account the relative values of the companies involved in the applicable transaction, and disregarding fractional shares with the amount and type of shares subject thereto to be conclusively determined by the Committee;

5.2 the unvested RSUs shall be converted into a cash payment obligation of the surviving or acquiring corporation in an amount equal to the proceeds a holder of the underlying shares would have received in proceeds from such transaction with respect to those shares, plus the related dividend equivalent cash payment with respect to the underlying Shares; or

5.3 all of the unvested RSUs shall immediately vest and the underlying Shares and related dividend equivalent cash payment shall be delivered simultaneously with the closing of the applicable transaction such that Recipient will participate as a shareholder in receiving proceeds from such transaction with respect to those Shares.

6. Changes in Capital Structure.

If, prior to the full vesting of all of the RSUs granted under this Agreement, the outstanding Common Stock of the Company is increased or decreased or changed into or exchanged for a different number or kind of shares or other securities of the Company by reason of any stock split, combination of shares or dividend payable in shares, recapitalization or reclassification, appropriate adjustment shall be made by the Committee in the number and kind of shares subject to the unvested RSUs so that Recipient's proportionate interest before and after the occurrence of the event is maintained. Notwithstanding the foregoing, the Committee shall have no obligation to effect any adjustment that would or might result in the issuance of fractional shares, and any fractional shares resulting from any adjustment may be disregarded or provided for in any manner determined by the Committee. Any such adjustments made by the Committee shall be conclusive.

7. Recoupment On Misconduct.

7.1 If at any time before a Change in Control and within three years after any date on which any RSUs vested, (a) the Company's financial statements for the corresponding Performance Year are the subject of a restatement due to the Misconduct (as defined below) of any person (whether or not Recipient was personally involved in such Misconduct), and (b) based on the Company's financial statements as restated, the Performance Threshold was not satisfied for that Performance Year, then Recipient shall repay to the Company the Shares (the "Excess Shares") and dividend equivalent cash payment (the "Excess Dividends") that vested under this Agreement on that vesting date. If any Excess Shares are sold by Recipient prior to the Company's demand for repayment (including any shares withheld for taxes under Section 4 of this Agreement), Recipient shall repay to the Company 100% of the proceeds of such sale or sales. The Committee may, in its sole discretion, reduce the amount to be repaid by Recipient to take into account the tax consequences of such repayment for Recipient.

7.2 If the Committee determines that Recipient engaged in any Misconduct after the date of this Agreement and prior to a sale of any of the Shares (the "Tainted Shares"), and this determination is made before a Change in Control and within three years after the vesting of the Tainted Shares, Recipient shall repay to the Company the Excess Proceeds (as defined below). The Committee may, in its sole discretion, reduce the amount of Excess Proceeds to be repaid by Recipient to take into account the tax consequences of such repayment or any other factors. The return of Excess Proceeds is in addition to and separate from any other relief available to the Company due to Recipient's Misconduct.

7.3 "Misconduct" shall mean (a) willful commission of an act of fraud or dishonesty resulting in economic or financial injury to the Company, (b) willful misconduct that substantially impairs the Company's business or reputation, or (c) willful gross negligence in the performance of the person's duties; provided, however, that such acts shall only constitute Misconduct if the Committee determines that such acts contributed to an obligation to restate the Company's financial statements for any quarter or year or otherwise had (or will have when publicly disclosed) an adverse impact on the market price of the Company Common Stock.

7.4 "Excess Proceeds" shall mean the excess of (a) the actual aggregate sales proceeds from Recipient's sales of Tainted Shares, over (b) the aggregate sales proceeds Recipient would have received from sales of Tainted Shares at a price per share determined appropriate by the Committee in its discretion to reflect what the market price of the Company Common Stock would have been if the restatement had occurred or other Misconduct had been disclosed prior to such sales.

7.5 If any portion of the Excess Shares and Excess Dividends was deferred under the DCP, that portion shall be recovered by canceling the amounts so deferred under the DCP and any dividends or other earnings credited under the DCP with respect to such cancelled amounts. The Company may seek direct repayment from Recipient of any Excess Shares, Excess Dividends and Excess Proceeds not so recovered and may, to the extent permitted by applicable law, offset such amounts against any compensation or other amounts owed by the Company to Recipient. In particular, such amounts may be recovered by offset against the after-tax proceeds of deferred compensation payouts under the DCP, Northwest Natural's Executive Supplemental Retirement Income Plan or Northwest Natural's Supplemental Executive Retirement Plan at the times such deferred compensation payouts occur under the terms of those plans. Amounts that remain unpaid for more than 60 days after demand by the Company shall accrue interest at the rate used from time to time for crediting interest under the DCP.

7.6 Notwithstanding the foregoing, if after the date of this Agreement the Company adopts a "claw-back" or similar policy, that policy as in effect at time the malfeasance is discovered by the Company triggering a claw-back shall supersede Sections 7.1 through 7.5 and shall be binding on Recipient.

8. Approvals.

The obligations of the Company under this Agreement are subject to the approval of state and federal authorities or agencies with jurisdiction in the matter. The Company will use its best efforts to take steps required by state or federal law or applicable regulations, including rules and regulations of the Securities and Exchange Commission and any stock exchange on which the Company's shares may then be listed, in connection with the award under this Agreement. The foregoing notwithstanding, the Company shall not be obligated to issue or deliver Common Stock under this Agreement if such issuance or delivery would violate applicable state or federal law.

9. No Right to Employment.

Nothing contained in this Agreement shall confer upon Recipient any right to be employed by the Employer or to continue to provide services to the Employer or to interfere in any way with the right of the Employer to terminate Recipient's services at any time for any reason, with or without cause.

10. Miscellaneous.

10.1 Entire Agreement; Amendment. This Agreement constitutes the entire agreement of the parties with regard to the subjects hereof and may be amended only by written agreement between the Company and Recipient.

10.2 Notices. Any notice required or permitted under this Agreement shall be in writing and shall be deemed sufficient when delivered personally to the party to whom it is addressed or when deposited into the United States Mail as registered or certified mail, return receipt requested, postage prepaid, addressed to the Company, Attention: Corporate Secretary, at its 250 SW Taylor Street, Portland, Oregon 97204 or to Employer, Attention: Corporate Secretary, at its principal executive offices, or to Recipient at the address of Recipient in the Company's records, or at such other address as such party may designate by ten (10) days' advance written notice to the other party.

10.3 Assignment; Rights and Benefits. Recipient shall not assign this Agreement or any rights hereunder to any other party or parties without the prior written consent of the Company. The rights and benefits of this Agreement shall inure to the benefit of and be enforceable by the Company's successors and assigns and, subject to the foregoing restriction on assignment, be binding upon Recipient's heirs, executors, administrators, successors and assigns.

10.4 Further Action. The parties agree to execute such further instruments and to take such further action as may reasonably be necessary to carry out the intent of this Agreement.

10.5 Applicable Law; Attorneys' Fees. The terms and conditions of this Agreement shall be governed by the laws of the State of Oregon. In the event either party institutes litigation hereunder, the prevailing party shall be entitled to reasonable attorneys' fees to be set by the trial court and, upon any appeal, the appellate court.

10.6 Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original.

11. Section 409A.

11.1 The intent of the parties is that payments and benefits under this Agreement comply with Section 409A of the Code ("Section 409A"), to the extent subject thereto, or otherwise be exempt from Section 409A, and accordingly, to the maximum extent permitted, this Agreement shall be interpreted and administered to be exempt from or in compliance therewith. Each amount to be paid or benefit to be provided under this Agreement shall be construed as a separate and distinct payment for purposes of Section 409A. Without limiting the foregoing and notwithstanding anything contained herein to the contrary, to the extent required to avoid accelerated taxation and/or tax penalties under Section 409A:

(a) Recipient shall not be considered to have terminated employment with the Company for purposes of any payments under this Agreement which are subject to Section 409A until Recipient would be considered to have incurred a "separation from service" from the Company within the meaning of Section 409A;

(b) Amounts that would otherwise be payable and benefits that would otherwise be provided pursuant to this Agreement or any other arrangement between Recipient and the Company during the six (6) month period immediately following Recipient's separation from service shall instead be paid on the first business day after the date that is six (6) months following Recipient's separation from service (or, if earlier, Recipient's date of death);

(c) Any payment that will be in compliance with Section 409A only if payable under designations permitted by Treas. Reg. Section 1.409A-3(c), or only if payable upon termination of a deferred compensation plan pursuant to Treas. Reg. Section 1.409A-3(j)(iv), shall be made only in compliance with such regulations;

(d) Any payment that will be in compliance with Section 409A only if payable upon a change in control event within the meaning Treas. Reg. Section 1.409A-3(i)(5) shall be made only in compliance with such regulation; and

(e) If any severance amount payable under any other agreement that Recipient may have a right or entitlement to as of the date of this Agreement constitutes deferred compensation under Section 409A, then the portion of the benefits payable hereunder equal to such other amount shall instead be provided in the form set forth in such other agreement.

11.2 The Company makes no representation that any or all of the payments described in this Agreement will be exempt from or comply with Section 409A and makes no undertaking to preclude Section 409A from applying to any such payment. Recipient understands and agrees that Recipient shall be solely responsible for the payment of any taxes, penalties, interest or other expenses incurred by Recipient on account of non-compliance with Section 409A.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the day and year first above written.

NORTHWEST NATURAL HOLDING COMPANY

By ________________________

Title ________________________

RECIPIENT

____

EXHIBIT A

EFFECTIVE INTEREST RATES OF OUTSTANDING LONG-TERM DEBT

The outstanding series or tranches of long-term debt of the Company outstanding as of the date of this Agreement and the Effective Interest Rate of each such series or tranche are as follows:

Series	**Effective Interest Rate**
NW Natural Gas Company (Corp 5000):	
3.542 % Series due 2023	3.696%
5.620 % Series due 2023	6.360%
7.720 % Series due 2025	8.336%
6.520 % Series due 2025	6.589%
7.050 % Series due 2026	7.121%
3.211 % Series due 2026	3.383%
7.000 % Series due 2027	7.062%
6.650 % Series due 2027	6.714%
2.822 % Series due 2027	2.966%
6.650 % Series due 2028	6.727%
3.141 % Series due 2029	3.275%
7.740 % Series due 2030	8.433%
7.850 % Series due 2030	8.551%
5.820 % Series due 2032	5.913%
5.660 % Series due 2033	5.723%
5.250 % Series due 2035	5.316%
4.000 % Series due 2042	4.062%
4.136 % Series due 2046	4.226%

3.685 % Series due 2047	3.754%
4.110 % Series due 2048	4.145%
3.869 % Series due 2049	3.938%
3.600 % Series due 2050	3.690%
3.078 % Series due 2051	3.135%
4.780 % Series due 2052	4.806%
NW Natural Water Company, LLC (Corp 6000):	
2.940 % weighted rate Notes	2.940%
SOFR Loan due 2024	4.267%
LIBOR Loan due 2026	2.556%
NW Natural Holding Company (Corp 1000):	
SOFR Loan due 2024	4.229%

As amended
effective February 23, 2023

NORTHWEST NATURAL GAS COMPANY
EXECUTIVE ANNUAL INCENTIVE PLAN

This amended Executive Annual Incentive Plan (the "Plan") is executed by Northwest Natural Gas Company, an Oregon corporation (the "Company"), effective February 23, 2023. Effective October 1, 2018, the Company became a wholly-owned subsidiary of Northwest Natural Holding Company ("Parent") and holders of Company common stock became holders of Parent common stock ("Parent Common Stock").

PURPOSE OF PLAN

The success of the Company is dependent upon its ability to attract and retain the services of key executives of the highest competence and to provide incentives for superior performance. The purpose of the plan is to advance the interests of the Company and its stakeholders through an incentive compensation program that will attract and retain key executives and motivate them to achieve performance goals.

PROGRAM TERM

This Plan is an annual incentive plan and each new calendar year commences a new Program Term. Each Program Term will begin on January 1 and conclude on December 31.

PARTICIPATION

All executive officers of the company and any other highly compensated employees as designated by the Company's Organization and Executive Compensation Committee (the "Committee") are eligible to receive awards ("Awards") under the Executive Annual Incentive Plan.

At the beginning of each Program Term, the Committee shall determine eligibility for Awards and establish for each participant, the target incentive level as a percentage of year-end annualized based salary ("Target Award"). This information will be set forth in Exhibit I of the Plan document for the Program Term. Each such participating employee shall be referred to as a "Participant."

To be eligible for payout of an Award the Participant must have a minimum of three months of service during the Program Term. If the Participant is a new employee or is newly eligible to participate in the Plan, that Participant must be in an eligible position on or before September 30 of the Program Term and will receive a prorated Award. In addition, the Participant must be employed by the Company or Parent on December 31 of the Program Term to be eligible for payout of the Award for the Program Term unless the Participant is eligible for a prorated Award as provided in the next sentence. Eligibility for a prorated Award occurs when a Participant has three or more months of participation in the Program Term but the Participant's employment is terminated prior to December 31 of the Program Term due to one of the following: Retirement (unless such Retirement results from a termination of the Participant's employment by the Company or Parent for Cause), disability and death. Prorated Awards will be determined by prorating the Participant's final Award by the number of days employed during the Program Term.

If a Participant is a party to a Change in Control Severance Agreement with the Company or a parent or subsidiary of the Company, and Participant becomes entitled to a Change in Control Severance Benefit (as defined below) before the end of the Program Term, then within ten days after the Participant's termination of employment such Participant will be paid a prorated Award equal to such person's Target Award multiplied by a fraction, the numerator of which is the number of days during the Program Term they were employed by the Employer (as defined below) and the denominator of which is 365. A "Change in Control Severance Benefit" means the severance benefit provided for in Participant's Change in Control Severance Agreement with the Company or a parent or subsidiary of the Company; provided, however, that such severance benefit is a "Change in Control Severance Benefit" for purposes of this Agreement only if, under the terms of Participant's Change in Control Severance Agreement, Participant becomes entitled to the severance benefit (a) after a change in control of the Company has occurred, (b) because Participant's employment with the Company or a parent or subsidiary of the Company ("Employer") has been terminated by Participant for good reason in accordance with the terms and conditions of the Change in Control Severance Agreement or by Employer other than for cause, and (c) because Participant has satisfied any other conditions or requirements specified in the Change in Control Severance Agreement and necessary for Participant to become entitled to receive the severance benefit. For purposes of this paragraph, the terms "change in control," "good reason," "cause" and "disability" shall have the meanings set forth in Participant's Change in Control Severance Agreement.

For a Participant who is <u>not</u> a party to a Change in Control Severance Agreement with Employer, if a Change of Control occurs during the Program Term and (a) Participant's employment is terminated by Employer (or its successor) without Cause (as defined below) prior to the end of the Program Term, or (b) Participant's employment is terminated by Participant for Good Reason (as defined below) prior to the end of the Program Term, then within ten days after the Participant's termination of employment such Participant will be paid a prorated Award equal to such person's Target Award multiplied by a fraction, the numerator of which is the number of days during the Program Term they were employed by Employer and the denominator of which is 365.

If a Change of Control occurs during the Program Term and a Participant remains employed by Employer through the end of the Program Term, such a Participant will receive a payout equal to their Target Award.

"Retirement" shall mean termination of employment after Participant is (a) age 62 with at least five years of service as an employee of the Company and Parent, or (b) age 55 with age plus years of service (including fractions) as an employee of the Company and Parent totaling at least 70.

"Cause" shall mean (a) the willful and continued failure by a Participant to perform substantially the Participant's assigned duties with the Company or Parent (other than any such failure resulting from incapacity due to physical or mental illness) after a demand for substantial performance is delivered to the Participant by the Company or Parent which specifically identifies the manner in which the Participant has not substantially performed such duties, (b) willful commission by a Participant of an act of fraud or dishonesty resulting in economic or financial injury to the Company or Parent, (c) willful misconduct by a Participant that substantially impairs the Company's or Parent's business or reputation, or (d) willful gross negligence by a Participant in the performance of his or her duties.

"Good Reason" shall mean the occurrence after Shareholder Approval, if applicable, or the Change in Control, of any of the following circumstances, but only if (x) Participant gives notice to Employer of Participant's intent to terminate employment for Good Reason within 30 days after the later of (1) notice to Participant of such circumstances, or (2) the Change in Control, and

(y) such circumstances are not fully corrected by the Employer within 90 days after Participant's notice:

(a) the assignment to Participant of a different title, job or responsibilities that results in a decrease in the level of Participant's responsibility; provided that Good Reason shall not exist if Participant continues to have the same or a greater general level of responsibility for the former Employer operations after the Change in Control as Participant had prior to the Change in Control even though such responsibilities have necessarily changed due to the former Employer operations becoming a subsidiary or division of the surviving company;

(b) a reduction by the Employer in Participant's base salary as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control;

(c) the failure by Employer to continue in effect any employee benefit or incentive plan in which Participant is participating immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control (or plans providing Participant with at least substantially similar benefits) other than as a result of the normal expiration of any such plan in accordance with its terms as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control, or the taking of any action, or the failure to act, by Employer which would adversely affect Participant's continued participation in any of such plans on at least as favorable a basis to Participant as is the case immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control or which would materially reduce Participant's benefits in the future under any of such plans or deprive Participant of any material benefit enjoyed by Participant immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control;

(d) the failure by the Employer to provide and credit Participant with the number of paid vacation days to which Participant is then entitled in accordance with the Employer's normal vacation policy as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control; or

(e) the Employer's requiring Participant to be based more than 25 miles from where Participant's office is located immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control except for required travel on the Employer's business to an extent substantially consistent with the business travel obligations which Participant undertook on behalf of the Employer prior to the earlier of Shareholder Approval, if applicable, or the Change in Control.

"Shareholder Approval" shall be deemed to have occurred if the shareholders of Parent approve an agreement entered into by Parent, the consummation of which would result in the occurrence of a Change in Control.

In the event of a change in job position during the Program Term, the Committee may, in its discretion, increase or decrease the amount of a Participant's Award to reflect such change.

INCENTIVE FORMULA

The formula for calculating Awards for each Program Term is as follows:

$$\text{Target Award} \times \left[\left(\text{Company Performance Factor (CPF)} \times \text{CPF Factor Weight}\right) + \left(\text{Priority/Individual Performance Factor (IPF)} \times \text{P/IPF Factor Weight}\right)\right] = \text{Participant Award}$$

COMPANY PERFORMANCE FACTOR

The Company performance goals in the Plan are intended to align the interest of Participants with those of the shareholders. The goals and the formula for determining the Company Performance Factor will be established by the Committee at the start of each Program Term and set forth as Exhibit II. The Committee may, at any time, approve adjustments to the calculation of the results under any Company performance goal to take into account such unanticipated circumstances or significant, non-recurring or unplanned events as the Committee may determine in its sole discretion, and such adjustments may increase or decrease the results. Possible circumstances that may be the basis for adjustments shall include, but not be limited to, any change in applicable accounting rules or principles; any gain or loss on the disposition of a business; impairment of assets; dilution caused by acquiring a business; tax changes and tax impacts of other changes; changes in applicable laws and regulations; changes in rate case timing; changes in the Company's structure; and any other circumstances outside of management's control.

PRIORITY/INDIVIDUAL PERFORMANCE FACTOR

The P/IPF weight used in calculating the Priority/Individual Performance Factor will be established for each Participant by the Committee at the beginning of the Program Term and set forth as part of Exhibit I. Also included in Exhibit I will be the CPF Factor Weight for the Company Performance Factor. Priority/Individual goals for each Participant will be established at the beginning of each Program Term and performance against these goals will be assessed by the Participant's superior and approved by the C.E.O. at the end of the Program Term. This assessment will result in a rating on a scale of 0% to 175%. This rating is called the Priority/Individual Performance Factor. The Participant will not receive a payout under the Priority/Individual Performance component of an Award if the Priority/Individual Performance Factor is less than 50%.

ADMINISTRATION

Award payouts will be calculated and paid no later than the March 15 following the end of the Program Term. Award payouts are subject to tax withholding unless the Participant made a prior election to defer the Award payout under the terms of the Deferred Compensation Plan for Directors and Executives ("DCP").

All Award payouts shall be audited by the Internal Audit department and approved by the Committee prior to payment.

The Plan shall be administered by the Committee. The Committee shall have the exclusive authority and responsibility for all matters in connection with the operation and administration of the Plan. Decisions by the Committee shall be final and binding upon all parties affected by the Plan, including the beneficiaries of Participants.

The Committee may rely on information and recommendations provided by management. The Committee may delegate to management the responsibility for decisions that it may make or actions that it may take under the terms of the Plan, subject to the Committee's reserved right to review such decisions or actions and modify them when necessary or appropriate under the circumstances. The Committee shall not allow any employee to obtain control over decisions or actions that affect that employee's Plan benefits.

RECOUPMENT ON EARNINGS RESTATEMENT

If at any time before a Change in Control and within three years after the payout of Awards for a Program Term, Parent's financial statements for that Program Term are the subject of a restatement due to the Misconduct of any person, each Participant who received an Award payout for that Program Term (whether or not such Participant was personally involved in such Misconduct) shall repay to the Company the Excess Bonus Compensation (as defined below). For purposes of the Plan, "Excess Bonus Compensation" for any Participant means the positive difference, if any, between (i) the Participant's Award payout as originally calculated, and (ii) the Participant's Award payout as recalculated with the results for Company performance goals being based on Parent's financial statements as restated. Excess Bonus Compensation shall not include any amounts in respect of any individual performance goals or in respect of Company performance goals that are not measured in whole or in part on financial results reported in Parent's financial statements. The Committee may, in its sole discretion, reduce the amount of Excess Bonus Compensation to be repaid by any Participant to take into account the tax consequences of such repayment for the Participant.

If any portion of an Award payout was deferred under the DCP, any Excess Bonus Compensation to be repaid with respect to that Award shall first be recovered by canceling all or a portion of the amount so deferred under the DCP and any interest credited under the DCP with respect to such cancelled amount. The Company may seek direct repayment from the Participant of any Excess Bonus Compensation not so recovered and may, to the extent permitted by applicable law, offset such Excess Bonus Compensation against any compensation or other amounts owed by the Company to the Participant. In particular, Excess Bonus Compensation may be recovered by offset against the after-tax proceeds of deferred compensation payouts under the DCP, the Company's Executive Supplemental Retirement Income Plan or the Company's Supplemental Executive Retirement Plan at the times such deferred compensation payouts occur under the terms of those plans. Excess Bonus Compensation that remains unpaid for more than 60 days after demand by the Company shall accrue interest at the rate used from time to time for crediting interest under the DCP.

"Misconduct" shall mean (a) willful commission by any person of an act of fraud or dishonesty or (b) willful gross negligence by any person in the performance of his or her duties.

Notwithstanding the foregoing, if after the date of this Plan the Company adopts a "claw-back" or similar policy, that policy as in effect at time the malfeasance is discovered by the Company triggering a claw-back shall supersede the foregoing "Recoupment on Earnings Restatement" provisions and shall be binding on Participants.

"Change in Control" shall mean the occurrence of any of the following events:

(a) The consummation of:

(i) any consolidation, merger or plan of share exchange involving Parent (a "Merger") as a result of which the holders of outstanding securities of Parent ordinarily having the right to vote for the election of directors ("Voting Securities") immediately prior to the Merger do not continue to hold at least 50% of the combined voting power of the outstanding Voting Securities of the surviving corporation or a parent corporation of the surviving corporation immediately after the Merger, disregarding any Voting Securities issued to or retained by such holders in respect of securities of any other party to the Merger;

(ii) any consolidation, merger, plan of share exchange or other transaction involving the Company as a result of which Parent does not continue to hold, directly or indirectly. at least 50% of the outstanding securities of the Company ordinarily having the right to vote for the election of directors; or

(iii) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all, or substantially all, the assets of Parent or the Company;

(b) At any time during a period of two consecutive years, individuals who at the beginning of such period constituted Parent's Board of Directors ("Incumbent Directors") shall cease for any reason to constitute at least a majority thereof; provided, however, that the term "Incumbent Director" shall also include each new director elected during such two-year period whose nomination or election was approved by two-thirds of the Incumbent Directors then in office; or

(c) Any person (as such term is used in Section 14(d) of the Securities Exchange Act of 1934, other than Parent or any employee benefit plan sponsored by Parent) shall, as a result of a tender or exchange offer, open market purchases or privately negotiated purchases from anyone other than Parent, have become the beneficial owner (within the meaning of Rule 13d-3 under the Securities Exchange Act of 1934), directly or indirectly, of Voting Securities representing twenty percent (20%) or more of the combined voting power of the then outstanding Voting Securities, but disregarding any Voting Securities with respect to which that acquirer has filed SEC Schedule 13G indicating that the Voting Securities were not acquired and are not held for the purpose of or with the effect of changing or influencing, directly or indirectly, the Company's management or policies, unless and until that entity or person files SEC Schedule 13D, at which point this exception will not apply to such Voting Securities, including those previously subject to a SEC Schedule 13G filing.

AMENDMENTS AND TERMINATION

The Board has the power to terminate this Plan at any time or to amend this Plan at any time and in any manner that it may deem advisable.

IN WITNESS WHEREOF this Plan was duly amended effective as of February 23, 2023.

NORTHWEST NATURAL GAS COMPANY

By: ______________________________

David H. Anderson

President and Chief Executive Officer

Exhibit I
Effective January 1, 2023

Participants, Target Awards and Individual Performance

Program Term: January 1, 2023 – December 31, 2023

Exhibit II

Company Performance Factor

Program Term: January 1, 2023 – December 31, 2023

Company Performance Factor Formula:

(Net Income Component X 71.43%) + (Operations Component X 28.57%) = Company Performance Factor

Net Income Component:

The Net Income (NI) Component will be determined using the formula in Note 1 below using Holding Company consolidated NI results. The table shows values rounded.

2023 NI Results	NI Performance Component
	0%
	50%
	100%
	175%

Notes on NI Component:

1) Values between those shown above will be interpolated using the formula shown below:

   Regression Interpolation Line for NI between $___ and $___ is y = ___x – ___and line for NI between $___ and $___ is y = ___x – ___ where X is the NI results for the year.

2) Final NI Numberwill be rounded to two places to the right of the decimal. This will be the same number as reported to shareholders before any approved exceptions.

Operations Component:

The Operations Component (which aligns with NBU incentive goals) for 2023 will be determined using the following formula and table:

$$\text{Sum of} \left[\text{Goal Performance Rating} \times \text{Goal Weight} \right] = \text{Operations Component Factor}$$

2023 Operational Goals

Goals	Goal Performance Rating		Goal Weight
Customer Satisfaction (Overall)	<u>**Cust. Sat.**</u> 0%	<u>**Rating**</u> 100% 200%	**16.667%**
Customer Satisfaction (Staff Interaction)	<u>**Cust. Sat.**</u> 200%	<u>**Rating**</u> 0% 100%	**16.667%**
Market Share & Growth (Total New Meter Sets)	<u>**Total New Meter Sets**</u> 0% 200%	<u>**Rating**</u> 100%	**16.667%**
Public Safety - Damages (% of calls w/response time less than 45 minutes)	<u>**% Call Rsp.**</u>	<u>**Rating**</u> 0% 100% 200%	**16.667%**
Public Safety - Odor Response (% of calls w/response time less than 45 minutes)	<u>**% Call Rsp.**</u>	<u>**Rating**</u> 0% 100% 200%	**16.667%**
Employee Safety Each factor weighted 50% **DART Rate** Days Away Restricted Time	<u>**DART Rate**</u>	<u>**Rating**</u> 0% 100% 200%	**16.667%**
PMVC No. of Preventable Motor Vehicle Collison (There will be no payout under this metric in the event of an on the job employee fatality due to a preventable safety incident)	<u>**PMVC**</u>	<u>**Rating**</u> 0% 100% 200%	
TOTAL			**100%**

Notes on Operations Goals:
1) Goal ratings will be interpolated between amounts shown.
2) The Goal Performance Rating for each goal is limited to 200%.
3) The Operations Component is limited to 200% and the aggregate performance from this component for use in the EAIP is limited to 175%.

Final Notes on Company Performance Factor and General:
1) Final EAIP Participant Awards to participants will be rounded up to the nearest $1,000.
2) Final NI results for 2023 could be adjusted for the impact of certain events as determined by the OECC.

February 23, 2023

[Name]
[Address]
[City, State Zip]

Re: Amended and Restated Change in Control Severance Agreement

Dear [Name]:

Northwest Natural Gas Company, an Oregon corporation (the “Company”), a wholly-owned subsidiary of Northwest Natural Holding Company, an Oregon corporation (“Parent”), considers the establishment and maintenance of a sound and vital management to be essential to protecting and enhancing the best interests of the Company. In this connection, the Company recognizes that, as is the case with many publicly held corporations like Parent, the possibility of a change in control may exist and that such possibility, and the uncertainty and questions which it may raise among management, may result in the departure or distraction of management personnel to the detriment of the Company, its customers and its shareholders. Accordingly, the Board of Directors of the Company (the “Board”) has determined that appropriate steps should be taken to reinforce and encourage the continued attention and dedication of members of the Company’s management to their assigned duties without distraction in circumstances arising from the possibility of a change in control of Parent or the Company.

In order to induce you to remain in the employ of the Company, this letter agreement, which has been approved by the Board, sets forth severance benefits which the Company agrees will be provided to you in the event your employment with the Company is terminated in connection with a Change in Control (as defined in Section 3 hereof) under the circumstances described below. The Company and you have entered into a prior letter agreement regarding change in control severance benefits dated October 1, 2018. Upon your signature of this letter agreement, that prior agreement as amended by the letter agreement between you and the Company dated [____________], shall be amended and restated in its entirety in the form of this agreement.

1. Agreement to Provide Services; Right to Terminate.

(i) Except as otherwise provided in paragraph (ii) below, the Company or you may terminate your employment at any time, subject to the Company’s providing the benefits hereinafter specified in accordance with the terms hereof.

(ii) In the event of a Potential Change in Control (as defined in Section 3 hereof), you agree that you will not leave the employ of the Company (other than as a result of Disability, as such term is hereinafter defined) and will render the services contemplated in the recitals to this Agreement until the earliest of (a) a date which is 270 days from the occurrence of such Potential Change in Control, or (b) a termination of your employment pursuant to which you become entitled under this Agreement to receive the benefits provided in Section 5(iii) below.

2. Term of Agreement. This Agreement shall commence on the date hereof and shall continue in effect until December 31, 2023; provided, however, that commencing on January 1, 2024 and each January 1 thereafter, the term of this Agreement shall automatically be extended for one additional year unless at least 90 days prior to such January 1 date, the Company or you shall have given notice that this Agreement shall not be extended (provided that no such notice may be given by the Company during the pendency of a Potential Change in Control); and provided, further, that this Agreement shall continue in effect for a period of twenty-four (24) months beyond the term provided herein if a Change in Control shall have occurred during such term. Notwithstanding anything in this Section 2 to the contrary, this Agreement shall terminate automatically if you or the Company terminate your employment prior to the earlier of Shareholder Approval (as defined in Section 3 hereof), if applicable, or the Change in Control. In addition, the Company may terminate this Agreement during your employment if, prior to the earlier of Shareholder Approval, if applicable, or the Change in Control, you cease to hold your current position with the Company, except by reason of a promotion.

3. Change in Control; Potential Change in Control; Shareholder Approval; Person.

(i) For purposes of this Agreement, a "Change in Control" shall mean the occurrence of any of the following events:

(A) The consummation of:

(1) any consolidation, merger or plan of share exchange involving Parent (a "Merger") as a result of which the holders of outstanding securities of Parent ordinarily having the right to vote for the election of directors ("Voting Securities") immediately prior to the Merger do not continue to hold at least 50% of the combined voting power of the outstanding Voting Securities of the surviving corporation or a parent corporation of the surviving corporation immediately after the Merger, disregarding any Voting Securities issued to or retained by such holders in respect of securities of any other party to the Merger;

(2) any consolidation, merger, plan of share exchange or other transaction involving the Company as a result of which Parent does not continue to hold, directly or indirectly, at least 50% of the outstanding securities of the Company ordinarily having the right to vote for the election of directors; or

(3) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all, or substantially all, the assets of Parent or the Company;

(B) At any time during a period of two consecutive years, individuals who at the beginning of such period constituted the board of directors of Parent ("Incumbent Directors") shall cease for any reason to constitute at least a majority thereof; provided, however, that the term "Incumbent Director" shall also include each new director elected during such two-year period whose nomination or election was approved by two-thirds of the Incumbent Directors then in office; or

(C) Any Person (as hereinafter defined) shall, as a result of a tender or exchange offer, open market purchases or privately negotiated purchases from anyone other than Parent, have become the beneficial owner (within the meaning of Rule 13d-3 under the Securities Exchange Act of 1934), directly or indirectly, of Voting Securities representing twenty percent (20%) or more of the combined voting power of the then outstanding Voting Securities, but disregarding any Voting Securities with respect to which that acquirer has filed SEC Schedule 13G indicating that the Voting Securities were not acquired and are not held for the purpose of or with the effect of changing or influencing, directly or indirectly, the Company's management or policies, unless and until that entity or person files SEC Schedule 13D, at which point this exception will not apply to such Voting Securities, including those previously subject to a SEC Schedule 13G filing.

Notwithstanding anything in the foregoing to the contrary, unless otherwise determined by the Board, no Change in Control shall be deemed to have occurred for purposes of this Agreement if (1) you acquire (other than on the same basis as all other holders of shares of Common Stock of Parent or the Company) an equity interest in an entity that acquires Parent or the Company in a Change in Control otherwise described under subparagraph (A) above, or (2) you are part of a group that constitutes a Person which becomes a beneficial owner of Voting Securities in a transaction that otherwise would have resulted in a Change in Control under subparagraph (C) above.

(ii) For purposes of this Agreement, a "Potential Change in Control" shall be deemed to have occurred if:

(A) Parent or the Company enters into an agreement, the consummation of which would result in the occurrence of a Change in Control;

(B) any Person (including Parent or the Company) publicly announces an intention to take or to consider taking actions which if consummated would constitute a Change in Control; or

(C) the Board adopts a resolution to the effect that, for purposes of this Agreement, a Potential Change in Control has occurred.

(iii) For purposes of this Agreement, "Shareholder Approval" shall be deemed to have occurred if the shareholders of Parent approve an agreement entered into by Parent, the consummation of which would result in the occurrence of a Change in Control.

(iv) For purposes of this Agreement, the term "Person" shall mean and include any individual, corporation, partnership, group, association or other "person," as such term is used in Section 14(d) of the Securities Exchange Act of 1934 (the "Exchange Act"), other than Parent or the Company or any employee benefit plan sponsored by Parent or the Company.

4. <u>Termination Following Shareholder Approval or Change in Control</u>. If a Change in Control occurs, you shall be entitled to the benefits provided in Section 5(iii) hereof in the event that (x) a Date of Termination (as defined in Section 4(v) below) of your employment with

the Company occurred or occurs after the earlier of Shareholder Approval, if applicable, or the Change in Control and no later than twenty-four (24) months after the Change in Control, or (y) your employment with the Company is terminated by you for Good Reason (as defined below) based on an event occurring concurrent with or subsequent to the earlier of Shareholder Approval, if applicable, or the Change in Control and your Notice of Termination (as defined in Section 4(iv) below) in connection therewith shall have been given no later than twenty-four (24) months after the Change in Control; provided, however, that if any such termination is (a) because of your death, (b) by the Company for Cause (as defined below) or Disability, or (c) by you other than for Good Reason based on an event occurring concurrent with or subsequent to the earlier of Shareholder Approval, if applicable, or the Change in Control, then you shall not be entitled to the benefits provided in Section 5(iii) hereof.

(i) Disability. Termination by the Company of your employment based on "Disability" shall mean termination because of your absence from your duties with the Company on a full-time basis for one hundred eighty (180) consecutive days as a result of your incapacity due to physical or mental illness, unless within thirty (30) days after Notice of Termination is given to you following such absence you shall have returned to the full-time performance of your duties.

(ii) Cause. Termination by the Company of your employment for "Cause" shall mean termination upon (a) the willful and continued failure by you to perform substantially your assigned duties with the Company (other than any such failure resulting from your incapacity due to physical or mental illness) after a demand for substantial performance is delivered to you by the Chair of the Board or Chief Executive Officer of the Company which specifically identifies the manner in which such executive believes that you have not substantially performed your duties or (b) the willful engaging by you in illegal conduct which is materially and demonstrably injurious to the Company. For purposes of this paragraph (ii), no act, or failure to act, on your part shall be considered "willful" unless done, or omitted to be done, by you in knowing bad faith and without reasonable belief that your action or omission was in, or not opposed to, the best interests of the Company. Any act, or failure to act, based upon authority given pursuant to a resolution duly adopted by the Board or based upon the advice of counsel for the Company shall be conclusively presumed to be done, or omitted to be done, by you in good faith and in the best interests of the Company. Notwithstanding the foregoing, you shall not be deemed to have been terminated for Cause unless and until there shall have been delivered to you a copy of a resolution duly adopted by the affirmative vote of not less than three-quarters of the entire membership of the Board at a meeting of the Board called and held for the purpose (after reasonable notice to you and an opportunity for you, together with your counsel, to be heard before the Board), finding that in the good faith opinion of the Board you were guilty of the conduct set forth above in (a) or (b) of this paragraph (ii) and specifying the particulars thereof in detail.

(iii) Good Reason. Termination by you of your employment with the Company for "Good Reason" shall mean termination by you of your employment with the Company based on any of the following events provided you give Notice of Termination after the occurrence of any of the following events and no later than 30 days after the later of (1) notice to you of such event, or (2) the Change in Control:

(A) a change in your status, title, position(s) or responsibilities as an officer of the Company which does not represent a promotion from your status, title, position(s) and responsibilities as in effect immediately prior to the earlier of Shareholder

Approval, if applicable, or the Change in Control, or the assignment to you of any duties or responsibilities which are inconsistent with such status, title or position(s), or any removal of you from or any failure to reappoint or reelect you to such position(s), except in connection with the termination of your employment for Cause or Disability or as a result of your death or by you other than for Good Reason; provided that, for the avoidance of doubt, if you are an officer of the Company or its affiliate and subject to the reporting requirements of Section 16 of the Securities Exchange Act of 1934, as amended (the "Exchange Act") with respect to those entities immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control, then being an officer of the surviving entity or its parent who is not subject to the reporting requirements of Section 16 of the Exchange Act of 1934 shall be deemed an adverse change to your status and responsibilities;

(B) a reduction by the Company in your base salary as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control;

(C) the failure by the Company or Parent, as applicable, to continue in effect any Plan (as hereinafter defined) in which you are participating immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control (or Plans providing you with at least substantially similar benefits) other than as a result of the normal expiration of any such Plan in accordance with its terms as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control, or the taking of any action, or the failure to act, by the Company or Parent which would adversely affect your continued participation in any of such Plans on at least as favorable a basis to you as is the case immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control or which would materially reduce your benefits in the future under any of such Plans or deprive you of any material benefit enjoyed by you immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control; provided that, for the avoidance of doubt, (1) if a Plan provides for payments to you after the termination of the Plan in accordance with its terms, any changes to the payments to be made to you under such Plan after its termination will be deemed a failure to continue such Plan in accordance with its terms, and (2) the failure to adopt a new annual incentive plan after the expiration of an annual incentive plan will be deemed to be the failure to continue in effect a Plan, even though the prior plan expired in accordance with its terms;

(D) the failure by the Company to (x) provide and credit you with the number of paid vacation days to which you are then entitled in accordance with the Company's normal vacation policy as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Controlor (y) to implement and honor a new vacation policy on substantially the same terms as the Company's vacation policy as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control;

(E) the Company's requiring you to be based more than 25 miles from where your office is located immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control except for required travel on the Company's business to an extent substantially consistent with the business travel obligations which you undertook on behalf of the Company prior to the earlier of Shareholder Approval, if applicable, or the Change in Control;

(F) the failure by the Company to obtain from any Successor (as hereinafter defined) the assent to this Agreement contemplated by Section 7 hereof;

(G) any purported termination by the Company of your employment which is not effected pursuant to a Notice of Termination satisfying the requirements of paragraph (iv) below (and, if applicable, paragraph (ii) above); and for purposes of this Agreement, no such purported termination shall be effective; or

(H) the failure by the Company to pay you any portion of your current compensation, to credit your account under any deferred compensation plan in accordance with your previous election, or to pay you any portion of an installment of deferred compensation under any Plan in which you participated, within seven (7) days of the date such compensation is due.

For purposes of this Agreement, "Plan" shall mean any compensation plan such as an incentive, stock option or restricted stock plan or any employee benefit plan such as a savings, pension, profit sharing, deferred compensation, medical, disability, accident, life insurance, or relocation plan or policy or any other plan, program or policy of the Company or Parent intended to benefit employees of the Company.

(iv) Notice of Termination. Any purported termination by the Company or by you (other than termination due to your death, which shall terminate your employment automatically) following the earlier of Shareholder Approval, if applicable, or a Change in Control shall be communicated by Notice of Termination to the other party hereto. For purposes of this Agreement, a "Notice of Termination" shall mean a notice which shall indicate the specific termination provision in this Agreement relied upon and shall set forth in reasonable detail the facts and circumstances claimed to provide a basis for termination of your employment under the provision so indicated.

(A) With respect to any Notice of Termination given by you for Good Reason, such Notice of Termination may indicate that such termination for Good Reason shall be conditioned upon, and postponed until, the date on which it is finally determined, either by mutual written agreement of the parties or by the arbitrators in a proceeding as provided in Section 13 hereof, that Good Reason exists for such termination. If a Notice of Termination given by you for Good Reason indicates that such termination shall be so conditioned and postponed, then, if the Company disputes the existence of Good Reason, the Company shall, within thirty (30) days after the Notice of Termination is given, notify you that a dispute exists concerning the termination, whereupon Section 13 hereof shall apply to such dispute. If no such notice is given by the Company within such 30-day period, then a final determination that Good Reason exists shall be deemed to have occurred on the date thirty (30) days after the Notice of Termination for Good Reason is given.

(B) Notwithstanding anything to the contrary in this Agreement:

(1) if, at any time before the Date of Termination determined pursuant to this Agreement with respect to any purported termination by you of your

employment with the Company, there exists a basis for the Company to terminate your employment for Cause, then the Company may, regardless of whether or not you have given Notice of Termination for Good Reason and regardless of whether or not Good Reason exists, terminate your employment for Cause, in which event you shall not be entitled to the benefits provided in Section 5(iii) hereof, and

(2) if you die or your employment is terminated based on Disability after you have given Notice of Termination for Good Reason and before the Date of Termination determined under this Agreement with respect to that Notice of Termination, and it is subsequently finally determined that Good Reason existed at the time your employment terminated, then termination of your employment shall be deemed to have occurred for Good Reason (and not due to your death or Disability) and you shall be entitled to the benefits provided in Section 5(iii) hereof.

(v) Date of Termination. "Date of Termination" shall mean the date your employment with the Company is terminated following the earlier of Shareholder Approval, if applicable, or a Change in Control, which date shall be determined as follows:

(A) if your employment is to be terminated for Disability, thirty (30) days after Notice of Termination is given (provided that, if you shall have returned to the performance of your duties on a full-time basis during such thirty (30) day period, then the termination for Disability contemplated by the Notice of Termination shall not occur),

(B) if your employment is terminated due to your death, the date of your death,

(C) if your employment is to be terminated by the Company other than for Disability, or if your employment is to be terminated by you without a claim of Good Reason, the date specified in the Notice of Termination, and

(D) if your employment is to be terminated by you for Good Reason, the date ninety (90) days after the date on which a Notice of Termination is given, unless either:

(1) an earlier date has been agreed to by the Company either in advance of, or after, receiving such Notice of Termination (in which case such earlier date shall be the Date of Termination),

(2) pursuant to and in accordance with Section 4(iv) you have indicated in your Notice of Termination that you are conditioning your termination upon (and postponing such termination until) the date on which it is finally determined that Good Reason exists for such termination (in which case the later of such date as determined in accordance with Section 4(iv) above, or the date otherwise determined under this Section 4(v)(D), shall be the Date of Termination),

(3) the Company shall not have notified you within fifteen (15) days after a Notice of Termination for Good Reason is given that it intends to fully correct the circumstances giving rise to Good Reason (in which case the date

fifteen (15) days after the Notice of Termination shall be the Date of Termination), or

(4) if the Company gives notice as provided in Section 4(v)(D)(3) and if the circumstances giving rise to Good Reason are fully corrected on or prior to the date that is ninety (90) days after such Notice of Termination was given, then the termination for Good Reason contemplated by such Notice of Termination shall not occur.

(E) You shall not be obligated to perform any services after the Date of Termination that would prevent the termination of your employment on such Date of Termination from qualifying as a "separation from service" as defined in Treasury Regulations §1.409A-1(h).

5. Compensation Upon Termination or During Disability.

(i) During any period following the earlier of Shareholder Approval, if applicable, or a Change in Control that you fail to perform your duties as a result of incapacity due to physical or mental illness, you shall continue to receive your full base salary at the rate then in effect and any benefits or awards under any Plans shall continue to accrue during such period, to the extent not inconsistent with such Plans, until your employment is terminated pursuant to and in accordance with Sections 4(i) and 4(v) hereof. Thereafter, your benefits shall be determined in accordance with the Plans then in effect.

(ii) If your employment shall be terminated for Cause or as a result of death following the earlier of Shareholder Approval, if applicable, or a Change in Control, the Company shall pay you your full base salary through the Date of Termination at the rate in effect just prior to the time a Notice of Termination is given plus any benefits or awards which pursuant to the terms of any Plans have been earned or become payable, but which have not yet been paid to you. Thereupon the Company shall have no further obligations to you under this Agreement.

(iii) If a Change in Control occurs and either (a) after the earlier of Shareholder Approval, if applicable, or the Change in Control and no later than twenty-four (24) months after the Change in Control, a Date of Termination of your employment with the Company occurred or occurs as a result of a termination by the Company other than for Cause or Disability, or (b) your employment with the Company is terminated by you for Good Reason based on an event occurring concurrent with or subsequent to the earlier of Shareholder Approval, if applicable, or the Change in Control and your Notice of Termination in connection therewith shall have been given no later than twenty-four (24) months after the Change in Control, then, by no later than the fifth day following the later of the Date of Termination or the Change in Control (except as may otherwise be provided), you shall be entitled, without regard to any contrary provisions of any Plan, to a severance benefit as follows:

(A) the Company shall pay your full base salary through the Date of Termination at the rate in effect just prior to the time a Notice of Termination is given plus any benefits or awards which pursuant to the terms of any Plans have been earned or become payable, but which have not yet been paid to you; provided, however, that with respect to a termination of your employment for Good Reason based on a reduction by the Company in your base salary as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control, the Company shall pay your full base salary through the Date of Termination at the rate in effect just prior to such reduction plus any benefits or awards which pursuant to the terms of any Plans have been earned or become payable, but which have not yet been paid to you;

(B) as severance pay and in lieu of any further salary for periods subsequent to the Date of Termination, the Company shall pay to you in a single payment an amount in cash equal to two (2.0) times the sum of (1) the greater of (i) your annual rate of base salary in effect on the Date of Termination or (ii) your annual rate of base salary in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control and (2) the your target annual bonus in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control;

(C) if you hold an equity award which vested upon consummation of the Change of Control on a prorated basis, the Company shall pay you an amount equal to (1) the amount you would have received if such award had fully vested (or vested at target performance) upon the consummation of the Change of Control minus (2) the amount paid to you with respect to such award based on the prorated vesting (without taking into account any tax withholding); and

(D) for a twenty-four (24) month period after the Date of Termination (specifically including a Date of Termination that occurs after Shareholder Approval and prior to a Change in Control), the Company shall arrange to provide you, your spouse and your dependents with life, accident and health insurance benefits substantially similar to those which you were receiving immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control. Such benefits may take the form, at the Company's discretion, of the Company's payment of COBRA or other premiums for you, your spouse and your dependents continued coverage under the Company’s group health plan and other insurance programs (if you, your spouse and your dependents are eligible for continuation coverage under the Company's group health plan and other insurance programs), payment of the premium for individual medical insurance policies and life and accident policies selected by you for you, your spouse and your dependents, or a combination of the foregoing.

Notwithstanding the foregoing, the Company shall not provide any benefit otherwise receivable by you pursuant to this subparagraph (C) to the extent that a similar benefit is actually received by you from a subsequent employer during such thirty (30) month period, and any such benefit actually received by you shall be reported to the Company.

(iv) The amount of any payment provided for in this Section 5 shall not be reduced, offset or subject to recovery by the Company by reason of any compensation earned by you as the result of employment by another employer after the Date of Termination, or otherwise. Your entitlements under Section 5(iii) are in addition to, and not in lieu of, any rights, benefits or entitlements you may have under the terms or provisions of any Plan.

6. Parachute Payments. Notwithstanding any other provision in this Agreement or any other agreement or arrangement between the Company or Parent and you with respect to compensation or benefits (each an “Other Arrangement”), in the event that the provisions of Sections 280G and 4999 of the Internal Revenue Code of 1986, as amended, or any successor provisions (the “Code”), would cause you to receive a greater after-tax benefit from the Capped

Benefit (as defined below) than from the amounts (including the monetary value of any non-cash benefits) otherwise payable pursuant to this Agreement or any Other Arrangement (the "Specified Benefits"), the Capped Benefit shall be paid to you in lieu of the Specified Benefits. The "Capped Benefit" shall equal the Specified Benefits, reduced by the amount necessary to prevent any portion of the Specified Benefits from being a "parachute payment" as defined in Section 280G(b)(2) of the Code. The Capped Benefit would therefore equal 2.99 multiplied by your applicable "base amount" as defined in Section 280G(b)(3) of the Code. For purposes of determining whether you would receive a greater after-tax benefit from the Capped Benefit than from the Specified Benefits, there shall be taken into account any excise tax that would be imposed under Section 4999 of the Code and all federal, state and local taxes required to be paid by you in respect of the receipt of such payments. The parties acknowledge that the application of Section 280G is uncertain in many respects and agree that the Company shall make all calculations and determinations under this section (including application and interpretation of the Code and related regulatory, administrative and judicial authorities) in good faith, which calculations and determinations shall be conclusive absent manifest error. The Company shall provide you with a reasonable opportunity to review and comment on the Company's calculations of the Capped Benefit and to request which of the Specified Benefits shall be reduced. If, after payment of any amount under this Agreement or any Other Arrangement, it is determined that the calculation of the Capped Benefit was calculated incorrectly, the amount of the Capped Benefit will be adjusted, the Company shall pay to you any additional amount that should have been paid to you, and you shall repay to the Company any amount that should not have been paid to you, in each case with interest at the discount rate applicable under Section 280G(d)(4) of the Code.

7. Successors; Binding Agreement.

(i) Upon your written request, the Company will seek to have any Successor (as hereinafter defined), by agreement in form and substance satisfactory to you, assent to the fulfillment by the Company of its obligations under this Agreement. For purposes of this Agreement, "Successor" shall mean any Person that succeeds to, or has the practical ability to control (either immediately or with the passage of time), the Company's business directly, by merger, consolidation or purchase of assets, or indirectly, by purchase of Parent's or the Company's Voting Securities or otherwise.

(ii) This Agreement shall inure to the benefit of and be enforceable by your personal or legal representatives, executors, administrators, successors, heirs, distributees, devisees and legatees. If you should die while any amount would still be payable to you hereunder if you had continued to live, all such amounts, unless otherwise provided herein, shall be paid in accordance with the terms of this Agreement to your devisee, legatee or other designee or, if there be no such designee, to your estate.

8. Fees and Expenses. The Company shall pay to you all legal fees and related expenses incurred by you in good faith as a result of (i) your termination following the earlier of Shareholder Approval, if applicable, or a Change in Control (including all such fees and expenses, if any, incurred in contesting or disputing in good faith any such termination) or (ii) your seeking to obtain or enforce in good faith any right or benefit provided by this Agreement.

9. Survival. The respective obligations of, and benefits afforded to, the Company and you as provided in Sections 5, 6, 7(ii), 8 and 13 of this Agreement shall survive termination

of this Agreement, but only with respect to a Change in Control occurring during the term of this Agreement.

10. Notice. For the purposes of this Agreement, notices and all other communications provided for in this Agreement shall be in writing and shall be deemed to have been duly given when delivered or mailed by United States registered mail, return receipt requested, postage prepaid and addressed to the address of the respective party set forth on the first page of this Agreement, provided that all notices to the Company shall be directed to the attention of the Chair of the Board or Chief Executive Officer of the Company, with a copy to the Secretary of the Company, or to such other address as either party may have furnished to the other in writing in accordance herewith, except that notice of change of address shall be effective only upon receipt.

11. Miscellaneous. No provision of this Agreement may be modified, waived or discharged unless such modification, waiver or discharge is agreed to in a writing signed by you and the Chair of the Board or Chief Executive Officer of the Company. No waiver by either party hereto at any time of any breach by the other party hereto of, or of compliance with, any condition or provision of this Agreement to be performed by such other party shall be deemed a waiver of similar or dissimilar provisions or conditions at the same or at any prior or subsequent time. No agreements or representations, oral or otherwise, express or implied, with respect to the subject matter hereof have been made by either party which are not expressly set forth in this Agreement. The validity, interpretation, construction and performance of this Agreement shall be governed by the laws of the State of Oregon.

12. Validity. The invalidity or unenforceability of any provision of this Agreement shall not affect the validity or enforceability of any other provision of this Agreement, which shall remain in full force and effect.

13. Arbitration. Any dispute or controversy arising under or in connection with this Agreement shall be settled exclusively by arbitration in Portland, Oregon by three arbitrators in accordance with the rules of the American Arbitration Association then in effect. Judgment may be entered on the arbitrators' award, which award shall be a final and binding determination of the dispute or controversy, in any court having jurisdiction; provided, however, that you shall be entitled to seek specific performance of your right to be paid until the Date of Termination during the pendency of any dispute or controversy arising under or in connection with this Agreement. The Company shall bear all costs and expenses of the arbitrators arising in connection with any arbitration proceeding pursuant to this Section 13.

14. Related Agreements. To the extent that any provision of any other agreement between the Company or any of its subsidiaries and you shall limit, qualify or be inconsistent with any provision of this Agreement, then for purposes of this Agreement, while the same shall remain in force, the provision of this Agreement shall control and such provision of such other agreement shall be deemed to have been superseded, and to be of no force or effect, as if such other agreement had been formally amended to the extent necessary to accomplish such purpose.

15. Section 409A.

(i) The intent of the parties is that payments and benefits under this Agreement comply with Section 409A of the Internal Revenue Code of 1986, as amended, and the regulations and guidance promulgated thereunder ("Section 409A"), to the extent subject thereto, or otherwise be exempt from Section 409A, and accordingly, to the maximum extent permitted, this Agreement shall be interpreted and administered to be exempt from or in compliance therewith. Each amount to be paid or benefit to be provided under this Agreement shall be construed as a separate and distinct payment for purposes of Section 409A. Without limiting the foregoing and notwithstanding anything contained herein to the contrary, to the extent required to avoid accelerated taxation and/or tax penalties under Section 409A:

(A) You shall not be considered to have terminated employment with the Company for purposes of any payments under this Agreement which are subject to Section 409A until you would be considered to have incurred a "separation from service" from the Company within the meaning of Section 409A;

(B) Amounts that would otherwise be payable and benefits that would otherwise be provided pursuant to this Agreement or any other arrangement between you and the Company during the six (6) month period immediately following your separation from service shall instead be paid on the first business day after the date that is six (6) months following your separation from service (or, if earlier, your date of death);

(C) Omitted

(D) Any payment that will be in compliance with Section 409A only if payable upon a change in control event within the meaning Treas. Reg. Section 1.409A-3(i)(5) shall be made only in compliance with such regulation; and

(E) If any severance amount payable under this Agreement or any other agreement that you may have a right or entitlement to as of the date of this Agreement constitutes deferred compensation under Section 409A, then the portion of the benefits payable hereunder equal to such other amount shall instead be provided in the form set forth in this Agreement or such other agreement.

(ii) The Company makes no representation that any or all of the payments described in this Agreement will be exempt from or comply with Section 409A and makes no undertaking to preclude Section 409A from applying to any such payment. You understand and agree that you shall be solely responsible for the payment of any taxes, penalties, interest or other expenses incurred by you on account of non-compliance with Section 409A.

15. Counterparts. This Agreement may be executed in several counterparts, each of which shall be deemed to be an original, but all of which together will constitute one and the same instrument.

If this letter correctly sets forth our agreement on the subject matter hereof, kindly sign and return to the Company the enclosed copy of this letter which will then constitute our agreement on this subject.

Sincerely,

NORTHWEST NATURAL GAS COMPANY

By: ___________________________

Name:_________________________
Title:

Agreed to this ____ day
of ____________, 2023.

____
[Name]

Exhibit 10s

NORTHWEST NATURAL HOLDING COMPANY
LONG TERM INCENTIVE PLAN
(as amended as of October 1, 2018 and February 23, 2023)

1. **Purpose**. The purpose of this Long Term Incentive Plan (the "Plan") is to enable Northwest Natural Holding Company (the "Company") to attract and retain the services of selected employees, officers and directors of the Company or of any subsidiary of the Company. The Plan was originally adopted by Northwest Natural Gas Company ("Northwest Natural"). Effective October 1, 2018, Northwest Natural became a wholly owned subsidiary of the Company and holders of Northwest Natural common stock became holders of Company common stock ("Common Stock"), and in connection with that transaction the Plan has been adopted and assumed by the Company and outstanding awards under the Plan have been assumed by the Company.

2. **Shares Subject to the Plan**. Subject to adjustment as provided below and in Section 9, the shares to be offered under the Plan shall consist of Common Stock of the Company, and the total number of shares of Common Stock that may be awarded under the Plan, including all shares of Northwest Natural common stock awarded under the Plan prior to its assumption by the Company, shall not exceed 1,100,000 shares. The shares awarded under the Plan may be authorized and unissued shares, reacquired shares or shares purchased on the open market for delivery to participants. If an option, Stock Award or Performance-based Award granted under the Plan expires, terminates or is cancelled, the shares subject to such option, Stock Award or Performance-based Award shall again be available under the Plan. If any shares delivered pursuant to a Stock Award or Performance-based Award under the Plan are forfeited to the Company, the number of shares forfeited shall again be available under the Plan.

3. **Duration of Plan**. The Plan shall continue in effect until all shares available for award under the Plan have been delivered to participants and all restrictions on such shares have lapsed; provided, however, that no awards shall be made under the Plan on or after the later of May 25, 2027 or the 10th anniversary of the last action after October 1, 2018 by the shareholders of the Company approving or re-approving the Plan. The Board of Directors may suspend or terminate the Plan at any time except with respect to awards and shares subject to restrictions then outstanding under the Plan. Termination shall not affect any outstanding awards or the forfeitability of shares awarded under the Plan.

4. **Administration**.

(a) ***Board of Directors.*** The Plan shall be administered by the Board of Directors of the Company, which shall determine and designate from time to time the individuals to whom awards shall be made, the amount of the awards and the other terms and conditions of the awards. Subject to the provisions of the Plan, the Board of Directors may from time to time adopt and amend rules and regulations relating to administration of the Plan, advance the lapse of any waiting period, accelerate any exercise date, waive or modify any restriction applicable to shares (except those restrictions imposed by law) and make all other determinations in the judgment of the Board of Directors necessary or desirable for the administration of the Plan. The interpretation and construction of the provisions of the Plan and related agreements by the Board of Directors shall be final and conclusive. The Board of Directors may correct any defect or supply any omission or reconcile any inconsistency in the Plan or in any related agreement in the manner and to the extent it shall deem expedient to carry the Plan into effect, and it shall be the sole and final judge of such expediency.

(b) ***Committee.*** The Board of Directors may delegate to a committee of the Board of Directors (the "Committee") any or all authority for administration of the Plan. If authority is delegated to a Committee, all references to the Board of Directors in the Plan shall mean and relate to the Committee except (i) as otherwise provided by the Board of Directors, and (ii) that only the Board of Directors may amend or terminate the Plan as provided in Sections 3 and 10.

(c) ***No Dividends on Unvested Awards.*** No award granted under the Plan shall provide for the payment of dividends on shares subject to the award before the shares have Vested; provided, however, that dividends accumulated between the grant date of an award and the Vesting date on shares that become Vested under the award may be paid to the recipient at or after the time the shares become Vested. "Vested" means that shares have been delivered to the recipient and are no longer subject to a substantial risk of forfeiture (as defined in regulations under Section 83 of the Internal Revenue Code of 1986, as amended ("IRC").

(d) ***Minimum Service Period.*** No award granted under the Plan on or after January 1, 2017 shall become Vested if the recipient does not remain in the service of the Company until the first anniversary of the date of grant, unless the recipient's service is terminated as a result of the recipient's death or physical disability (within the meaning of Section 22(e)(3) of the IRC), or such earlier Vesting occurs as a result of a Change in Control of the Company; provided, however, that the foregoing prohibition shall not apply to five percent of the sum of the number of shares available for awards under the Plan on January 1, 2017 plus the number of additional shares that thereafter become available.

(e) ***Change in Control Vesting.*** No award granted under the Plan on or after January 1, 2017 shall provide for any excuse from satisfaction of the continued service conditions of the award as a result of a Change in Control of the Company, except that an award agreement may excuse the recipient from the continued service obligation if:

(i) the recipient's employment is terminated by the employer without cause or by the recipient for good reason in connection with the Change in Control under terms specified in the award agreement; or

(ii) the award is not converted into an award for stock of the surviving or acquiring corporation in the Change in Control transaction under terms specified in the award agreement.

(f) ***Change in Control Definition.*** For purposes of the Plan, a "Change in Control" shall mean the occurrence of any of the following events:

(i) The consummation of:

(1) any consolidation, merger or plan of share exchange involving the Company (a "Merger") as a result of which the holders of outstanding securities of the Company ordinarily having the right to vote for the election of directors ("Voting Securities") immediately prior to the Merger do not continue to hold at least 50% of the combined voting power of the outstanding Voting Securities of the surviving corporation or a parent corporation of the surviving corporation immediately after the Merger, disregarding any Voting Securities issued to or retained by such holders in respect of securities of any other party to the Merger;

(2) any consolidation, merger, plan of share exchange or other transaction involving NW Natural or an affiliate of the Company specified in the award agreement with the recipient approved by the Board of Directors (a "Business Unit") as a result of which the Company does not continue to hold, directly or indirectly. at least 50% of the outstanding securities of NW Natural or the Business Unit, if applicable, ordinarily having the right to vote for the election of directors; or

(3) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all, or substantially all, the assets of the Company, NW Natural, or, the Business Unit, if applicable;

(ii) At any time during a period of two consecutive years, individuals who at the beginning of such period constituted the Board ("Incumbent Directors") shall cease for any reason to constitute at least a majority thereof; provided, however, that the term "Incumbent Director" shall also include each new director elected during such two-year period whose nomination or election was approved by two-thirds of the Incumbent Directors then in office; or

(iii) Any person (as such term is used in Section 14(d) of the Securities Exchange Act of 1934, other than the Company or any employee benefit plan sponsored by the Company) shall, as a result of a tender or exchange offer, open market purchases or privately negotiated purchases from anyone other than the Company, have become the beneficial owner (within the meaning of Rule 13d-3 under the Securities Exchange Act of 1934), directly or indirectly, of Voting Securities representing twenty percent (20%) or more of the combined voting power of the then outstanding Voting Securities, but disregarding any Voting Securities with respect to which that acquirer has filed SEC Schedule 13G indicating that the Voting Securities were not acquired and are not held for the purpose of or with the effect of changing or influencing, directly or indirectly, the Company's management or policies, unless and until that entity or person files SEC Schedule 13D, at which point this exception will not apply to such Voting Securities, including those previously subject to a SEC Schedule 13G filing.

5. **Types of Awards; Eligibility**. The Board of Directors may, from time to time, take the following actions, separately or in combination, under the Plan: (i) grant Stock Awards, including restricted stock and restricted stock units, as provided in Section 6; (ii) grant stock options as provided in Section 7; and (iii) grant Performance-based Awards as provided in Section 8. An award may be made to any employee, officer or director of the Company or any subsidiary of the Company, except that no stock option or Performance-based Award may be granted to any director who is not also an employee of the Company. The Board of Directors shall select the individuals to whom awards shall be made and shall specify the action taken with respect to each individual to whom an award is made.

6. **Stock Awards, including Restricted Stock and Restricted Stock Units**. The Board of Directors may grant shares as stock awards under the Plan ("Stock Awards"). No director of the Company who is not also an employee of the Company may be granted Stock Awards in any fiscal year for more than $300,000 in fair market value (as defined in Section 7(c)) of Common Stock. Stock Awards shall be subject to the terms, conditions and restrictions determined by the Board of Directors. The restrictions may include restrictions concerning transferability and forfeiture of the shares awarded, together with any other restrictions determined by the Board of Directors. Stock Awards subject to restrictions may be either restricted stock awards under which shares are delivered immediately upon grant subject to forfeiture if vesting conditions are not satisfied, or restricted stock unit awards under which shares are not delivered until after vesting conditions are satisfied. The Board of Directors may require the recipient to sign an agreement as a condition of the award, but may not require the recipient to pay any monetary consideration other than amounts necessary to satisfy tax withholding requirements. The agreement may contain any terms, conditions, restrictions, representations and warranties required by the Board of Directors. The certificates representing the shares awarded shall bear any legends required by the Board of Directors. The Company may require any recipient of a Stock Award to pay to the Company in cash or by check upon demand amounts necessary to satisfy any applicable federal, state or local tax withholding requirements. If the recipient fails to pay the amount demanded, the Company may withhold that amount from other amounts payable to the recipient, including salary, subject to applicable law. With the consent of the Board of Directors, a recipient may satisfy this obligation, in whole or in part, by instructing the Company to withhold from any shares to be received or by delivering to the Company other shares of Common Stock; provided, however, that the number of shares so withheld or delivered shall not exceed the minimum amount necessary to satisfy the required tax withholding obligation. Upon the delivery of shares under a Stock Award, the number of shares reserved for award under the Plan shall be reduced by the number of shares delivered, less the number of shares withheld or delivered to satisfy tax withholding obligations; provided, however, that effective for shares delivered on and after January 1, 2017, the adjustment for shares withheld or delivered to satisfy tax withholding obligations shall no longer apply.

7. **Stock Options**.

(a) ***Option Grants.*** Options granted under the Plan may be Incentive Stock Options as defined in Section 422 of the IRC, or Non-Statutory Stock Options. A Non-Statutory Stock Option means an option other than an Incentive Stock Option. The Board of Directors has the sole discretion to determine which options shall be Incentive Stock Options and which options shall be Non-Statutory Stock Options, and, at the time of grant, it shall specifically designate each option granted under the Plan as an Incentive Stock Option or a Non-Statutory Stock Option. In the case of Incentive Stock Options, all terms shall be consistent with the requirements of the IRC and applicable regulations. No Incentive Stock Option may be granted under the Plan on or after the tenth anniversary of the last action by the Board of Directors approving an increase in the number of shares available for issuance under the Plan, which action was subsequently approved within 12 months by the shareholders.

(b) ***Limitation on Amount of Grants***. No employee may be granted options under the Plan for more than 200,000 shares of Common Stock in any fiscal year.

(c) ***Option Price***. The option price per share under each option granted under the Plan shall be determined by the Board of Directors, but the option price for an Incentive Stock Option and a Non-Statutory Stock Option shall be not less than 100 percent of the fair market value of the shares covered by the option on the date the option is granted. Except as otherwise expressly provided, for purposes of the Plan, the fair market value shall be deemed to be the closing sales price for the Common Stock as reported by the New York Stock Exchange and published in the *Wall Street Journal* for the date of grant, or such other fair market value of the Common Stock as determined by the Board of Directors of the Company.

(d) ***Duration of Options***. Each option granted under the Plan shall continue in effect for the period fixed by the Board of Directors, except that no Incentive Stock Option shall be exercisable after the expiration of 10 years from the date it is granted and no Non-Statutory Stock Option shall be exercisable after the expiration of 10 years plus seven days from the date it is granted.

(e) ***Nonassignability***. Except as otherwise provided by the Board of Directors, each option granted under the Plan by its terms shall be nonassignable and nontransferable by the optionee except by will or by the laws of descent and distribution of the state or country of the optionee's domicile at the time of death, and each option by its terms shall be exercisable during the optionee's lifetime only by the optionee.

(f) ***Option Agreements***. The Board of Directors shall determine the employees to whom options shall be granted and the number of shares, option price, the period of each option, the time or times at which options may be exercised, and any other term of the grant, all of which shall be set forth in an option agreement between the Company and the optionee.

(g) ***Effect on Shares Available***. Upon the exercise of an option, the number of shares available for issuance under the Plan shall be reduced by the number of shares for which the option was exercised, without any adjustment for shares surrendered in payment of the option price or surrendered or withheld to satisfy tax withholding requirements.

(h) ***No Repricing***. Except for actions approved by the shareholders of the Company or adjustments made pursuant to Section 9, the option price for an outstanding option granted under the Plan may not be decreased after the date of grant nor may the Company grant a new option or pay any cash or other consideration (including another award under the Plan) in exchange for any outstanding option granted under the Plan at a time when the option price of the outstanding option exceeds the fair market value of the shares covered by the option.

8. **Performance-based Awards**. The Board of Directors may grant awards intended to qualify as qualified performance-based compensation under Section 162(m) of the IRC and the regulations thereunder ("Performance-based Awards"). Performance-based Awards shall be denominated at the time of grant either in Common Stock ("Stock Performance Awards") or in dollar amounts ("Dollar Performance Awards"). Payment under a Stock Performance Award or a Dollar Performance Award shall be made, at the discretion of the Board of Directors, in Common Stock ("Performance Shares"), or in cash or in any combination thereof. Performance-based Awards shall be subject to the following terms and conditions:

(a) ***Award Period.*** The Board of Directors shall determine the period of time for which a Performance-based Award is made (the "Award Period").

(b) ***Performance Goals and Payment.*** The Board of Directors shall establish in writing objectives ("Performance Goals") that must be met by the Company or any subsidiary, division or other unit of the Company ("Business Unit") during the Award Period as a condition to payment being made under the Performance-based Award. The Performance Goals for each award shall be one or more targeted levels of performance with respect to one or more of the following objective measures with respect to the Company or any Business Unit: earnings, earnings per share, stock price increase, total shareholder return (stock price increase plus dividends), return on equity, return on assets, return on capital, economic value added, revenues, operating income, inventories, inventory turns, cash flows or any of the foregoing before the effect of acquisitions, divestitures, accounting changes, and restructuring and special charges (determined according to criteria established by the Board of Directors). The Board of Directors shall also establish the number of Performance Shares or the amount of cash payment to be made under a Performance-based Award if the Performance Goals are met or exceeded, including the fixing of a maximum payment (subject to Section 8(d)). The Board of Directors may establish other restrictions to payment under a Performance-based Award, such as a continued employment requirement, in addition to satisfaction of the Performance Goals. Some or all of the Performance Shares may be delivered to the participant at the time of the award as restricted shares subject to forfeiture in whole or in part if Performance Goals or, if applicable, other restrictions are not satisfied.

(c) ***Computation of Payment.*** During or after an Award Period, the performance of the Company or Business Unit, as applicable, during the period shall be measured against the Performance Goals. If the Performance Goals are not met, no payment shall be made under a Performance-based Award. If the Performance Goals are met or exceeded, the Board of Directors shall certify that fact in writing and certify the number of Performance Shares earned or the amount of cash payment to be made under the terms of the Performance-based Award.

(d) ***Maximum Awards.*** No participant may receive in any fiscal year Stock Performance Awards under which the aggregate amount payable under the Awards exceeds the equivalent of 50,000 shares of Common Stock or Dollar Performance Awards under which the aggregate amount payable under the Awards exceeds $1,000,000.

(e) ***Tax Withholding.*** Each participant who has received Performance Shares shall, upon notification of the amount due, pay to the Company in cash or by check amounts necessary to satisfy any applicable federal, state and local tax withholding requirements. If the participant fails to pay the amount demanded, the Company or the Employer may withhold that amount from other amounts payable to the participant, including salary, subject to applicable law. With the consent of the Board of Directors, a participant may satisfy this obligation, in whole or in part, by instructing the Company to withhold from any shares to be received or by delivering to the Company other shares of Common Stock; provided, however, that the number of shares so delivered or withheld shall not exceed the minimum amount necessary to satisfy the required tax withholding obligation.

(f) ***Effect on Shares Available.*** The payment of a Performance-based Award in cash shall not reduce the number of shares of Common Stock reserved for award under the Plan. The number of shares of Common Stock reserved for award under the Plan shall be reduced by the number of shares delivered to the participant upon payment of an award, less the number of shares delivered or withheld to satisfy tax withholding obligations; provided, however, that effective for shares delivered on and after January 1, 2017, the adjustment for shares withheld or delivered to satisfy tax withholding obligations shall no longer apply.

9. **Changes in Capital Structure.** If the outstanding Common Stock of the Company is hereafter increased or decreased or changed into or exchanged for a different number or kind of shares or other securities of the Company by reason of any stock split, combination of shares or dividend payable in shares, recapitalization or reclassification, appropriate adjustment shall be made by the Board of Directors in the number and kind of shares available for grants under the Plan. In addition, the Board of Directors shall make appropriate adjustment in the number and kind of shares subject to outstanding awards, and in the exercise price of outstanding options, so that the recipient's proportionate interest before and after the occurrence of the event is maintained. Notwithstanding the foregoing, the Board of Directors shall have no obligation to effect any adjustment that would or might result in the award of fractional shares, and any fractional shares resulting from any adjustment may be disregarded or provided for in any manner determined by the Board of Directors. Any such adjustments made by the Board of Directors shall be conclusive.

10. **Amendment of Plan**. The Board of Directors may at any time, and from time to time, modify or amend the Plan in such respects as it shall deem advisable because of changes in the law while the Plan is in effect or for any other reason. Except as provided in Section 9, however, no change in an award already granted shall be made without the written consent of the holder of such award.

11. **Approvals**. The obligations of the Company under the Plan are subject to the approval of state and federal authorities or agencies with jurisdiction in the matter. The Company will use its best efforts to take steps required by state or federal law or applicable regulations, including rules and regulations of the Securities and Exchange Commission and any stock exchange on which the Company's shares may then be listed, in connection with the grants under the Plan. The foregoing notwithstanding, the Company shall not be obligated to issue or deliver Common Stock under the Plan if such issuance or delivery would violate applicable state or federal securities laws.

12. **Employment and Service Rights**. Nothing in the Plan or any award pursuant to the Plan shall (i) confer upon any employee any right to be continued in the employment of the Company or any subsidiary or interfere in any way with the right of the Company or any subsidiary by whom such employee is employed to terminate such employee's employment at any time, for any reason, with or without cause, or to decrease such employee's compensation or benefits, or (ii) confer upon any person engaged by the Company any right to be retained or employed by the Company or to the continuation, extension, renewal, or modification of any compensation, contract, or arrangement with or by the Company.

13. **Rights as a Shareholder**. The recipient of any award under the Plan shall have no rights as a shareholder with respect to any Common Stock until the date the recipient becomes the holder of record of those shares. Except as otherwise expressly provided in the Plan, no adjustment shall be made for dividends or other rights for which the record date occurs prior to the date the recipient becomes the holder of record.

AMENDMENT TO PERFORMANCE SHARE LONG TERM INCENTIVE AGREEMENT

The Performance Share Long Term Incentive Agreement between Northwest Natural Holding Company, an Oregon corporation (the "Company"), and ________ ("Recipient") dated February ___, 202_ (the "Agreement") is hereby amended by this amendment (the "Amendment") as follows:

1. Section 3.3 of the Agreement is amended to read in its entirety as follows:

"3.3 CIC Acceleration.

(a) If Recipient is a party to a Change in Control Severance Agreement with the Company or a parent or subsidiary of the Company, Recipient shall immediately be paid the Target Share Amount if Recipient becomes entitled to a Change in Control Severance Benefit (as defined below). "Change in Control Severance Benefit" means the severance benefit provided for in Recipient's Change in Control Severance Agreement with the Company or a parent or subsidiary of the Company; provided, however, that such severance benefit is a "Change in Control Severance Benefit" for purposes of this Agreement only if, under the terms of Recipient's Change in Control Severance Agreement, Recipient becomes entitled to the severance benefit (i) after a Change in Control of the Company has occurred, (ii) because Recipient's employment with the Employer has been terminated by Recipient for good reason in accordance with the terms and conditions of the Change in Control Severance Agreement or by the Employer other than for cause, and (iii) because Recipient has satisfied any other conditions or requirements specified in the Change in Control Severance Agreement and necessary for Recipient to become entitled to receive the severance benefit. For purposes of this Section 3.3(a), the terms "change in control," "good reason," "cause" and "disability" shall have the meanings set forth in Recipient's Change in Control Severance Agreement.

(b) If Recipient is not a party to a Change in Control Severance Agreement with the Company or a parent or subsidiary of the Company, Recipient shall immediately be paid the Target Share Amount if a Change in Control (as defined in Section 3.7 below) occurs and at any time after the earlier of Shareholder Approval (as defined in Section 3.8 below), if any, or the Change in Control and on or before the second anniversary of the Change in Control, (i) Recipient's employment is terminated by the Employer (or its successor) without Cause (as defined in Section 3.6 below), or (b) Recipient's employment is terminated by Recipient for Good Reason (as defined in Section 3.9 below)."

2. Section 3.7(c) is amended and restated to read in its entirety as follows:

"(c) Any person (as such term is used in Section 14(d) of the Securities Exchange Act of 1934, other than the Company or any employee benefit plan sponsored by the Company or NW Natural) shall, as a result of a tender or exchange offer, open market purchases or privately negotiated purchases from anyone other than the Company, have become the beneficial owner (within the meaning of Rule 13d-3 under the Securities Exchange Act of 1934), directly or indirectly, of Voting Securities representing twenty percent (20%) or more of the combined voting power of the then outstanding Voting Securities, but disregarding any Voting Securities with respect to which that acquirer has filed SEC Schedule 13G indicating that the Voting Securities were not acquired and are not held for the purpose of or with the effect of changing or influencing, directly or indirectly, the Company's management or policies, unless and until that entity or person files SEC Schedule 13D, at which point this exception will not apply to such Voting Securities, including those previously subject to a SEC Schedule 13G filing."

3. A new Section 9.4 is added to read in its entirety as follows:

"9.4 Notwithstanding the foregoing, if after the date of this Agreement the Company adopts a "claw-back" or similar policy, that policy as in effect at time the malfeasance is discovered by the Company triggering a claw-back shall supersede Sections 9.1 through 9.3 and shall be binding on Recipient."

4. A new Section 13 is added to read in its entirety as follows:

"13. Section 409A.

13.1 The intent of the parties is that payments and benefits under this Agreement comply with Section 409A of the Code ("Section 409A"), to the extent subject thereto, or otherwise be exempt from Section 409A, and accordingly, to the maximum extent permitted, this Agreement shall be interpreted and administered to be exempt from or in compliance therewith. Each amount to be paid or benefit to be provided under this Agreement shall be construed as a separate and distinct payment for purposes of Section 409A. Without limiting the foregoing and notwithstanding anything contained herein to the contrary, to the extent required to avoid accelerated taxation and/or tax penalties under Section 409A:

(a) Recipient shall not be considered to have terminated employment with the Company for purposes of any payments under this Agreement which are subject to Section 409A until Recipient would be considered to have incurred a "separation from service" from the Company within the meaning of Section 409A;

(b) Amounts that would otherwise be payable and benefits that would otherwise be provided pursuant to this Agreement or any other arrangement between Recipient and the Company during the six (6) month period immediately following Recipient's separation from service shall instead be paid on the first business day after the date that is six (6) months following Recipient's separation from service (or, if earlier, Recipient's date of death);

(c) Any payment that will be in compliance with Section 409A only if payable under designations permitted by Treas. Reg. Section 1.409A-3(c), or only if payable upon termination of a deferred compensation plan pursuant to Treas. Reg. Section 1.409A-3(j)(iv), shall be made only in compliance with such regulations;

(d) Any payment that will be in compliance with Section 409A only if payable upon a change in control event within the meaning Treas. Reg. Section 1.409A-3(i)(5) shall be made only in compliance with such regulation; and

(e) If any severance amount payable under any other agreement that Recipient may have a right or entitlement to as of the date of this Agreement constitutes deferred compensation under Section 409A, then the portion of the benefits payable hereunder equal to such other amount shall instead be provided in the form set forth in such other agreement.

13.2 The Company makes no representation that any or all of the payments described in this Agreement will be exempt from or comply with Section 409A and makes no undertaking to preclude Section 409A from applying to any such payment. Recipient understands and agrees that Recipient shall be solely responsible for the payment of any taxes, penalties, interest or other expenses incurred by Recipient on account of non-compliance with Section 409A."

5. Except as otherwise provided herein, all other provisions of the Agreement shall remain in full force and effect.

Dated: as of February __, 2023.

NORTHWEST NATURAL HOLDING COMPANY	RECIPIENT
By: ______________________	______________________
[____________]	[____________]

PERFORMANCE SHARE LONG TERM INCENTIVE AGREEMENT

This Agreement is entered into as of February __, 2023, between Northwest Natural Holding Company, an Oregon corporation (the “Company”), and ____________ (“Recipient”).

On February 22, 2023, the Organization and Executive Compensation Committee (the “Committee”) of the Company’s Board of Directors (the “Board”) authorized a performance-based stock award (the “Award”) to Recipient pursuant to Section 6 of the Company’s Long Term Incentive Plan (the “Plan”). Recipient desires to accept the Award subject to the terms and conditions of this Agreement.

NOW, THEREFORE, the parties agree as follows:

1. Award. Subject to the terms and conditions of this Agreement, the Company shall issue or otherwise deliver to the Recipient the number of shares of Common Stock of the Company (the “Performance Shares”) determined under this Agreement based on (a) the performance of the Company during the three-year period from January 1, 2023 to December 31, 2025 (the “Award Period”) as described in Section 2 and (b) Recipient’s continued employment during the Award Period as described in Section 3. If the Company issues or otherwise delivers Performance Shares to Recipient, the Company shall also pay to Recipient the amount of cash determined under Section 4 (the “Dividend Equivalent Cash Award”). Recipient’s “Target Share Amount” for purposes of this Agreement is __________ shares.

2. Performance Conditions.

2.1 Payout Factor. Subject to possible reduction under Section 3, the number of Performance Shares to be issued or otherwise delivered to Recipient shall be determined by multiplying the Payout Factor (as defined below) by the Target Share Amount. The “Payout Factor” shall be equal to (a) the TSR Modifier as determined under Section 2.2, multiplied by (b) the EPS Payout Factor as determined under Section 2.3 below; provided, however, that the Payout Factor shall not be greater than 200% and the Payout Factor shall be 0% if the ROIC Performance Threshold (as defined in Section 2.4 below) is not satisfied. Notwithstanding the foregoing, if a Change in Control (as defined in Section 3.7) occurs before the last day of the Award Period, the Payout Factor shall be 100%.

2.2 TSR Modifier.

(a) The “TSR Modifier” shall be determined under the table below based on the TSR Percentile Rank (as defined below) of the Company:

TSR Percentile Rank	TSR Modifier
less than 25%	75%
25% to 75%	100%
more than 75%	125%

(b) To determine the Company’s “TSR Percentile Rank,” the TSR of the Company and each of the Peer Group Companies (as defined below) shall be calculated, and the Peer Group Companies shall be ranked based on their respective TSR’s from lowest to highest. If the Company’s TSR is equal to the TSR of any other Peer Group Company, the Company’s TSR Percentile Rank shall be equal to the number of Peer Group Companies with a lower TSR divided by the number that is one less than the total number of Peer Group Companies, with the resulting amount expressed as a percentage and rounded to the nearest tenth of a percentage point. If the Company’s TSR is between the TSRs of any two Peer Group Companies, the TSR Percentile Ranks of those two Peer Group Companies shall be determined as set forth in the preceding sentence, and the Company's TSR Percentile Rank shall be interpolated as follows. The excess of the Company's TSR over the TSR of the lower Peer Group Company shall be divided by the excess of the TSR of the higher Peer Group Company over the TSR of the lower Peer Group Company. The resulting fraction shall be multiplied by the difference between the TSR Percentile Ranks of the two Peer Group Companies. The product of that calculation shall be added to the TSR Percentile Rank of the lower Peer Group Company, and the resulting sum (rounded to the nearest tenth of a percentage point) shall be the Company's TSR Percentile Rank. The intent of this definition of TSR Percentile Rank is to produce the same result as calculated using the PERCENTRANK function in Microsoft Excel to determine the rank of the Company's TSR within the array consisting of the TSRs of the Peer Group Companies.

(c) The "Peer Group Companies" consist of those companies set forth on Exhibit A that continue to have publicly-traded common stock through December 31, 2025.

(d) The "TSR" for the Company and each Peer Group Company shall be calculated by (1) assuming that $100 is invested in the common stock of the company at a price equal to the average of the closing market prices of the stock for the period from October 1, 2022 to December 31, 2022, (2) assuming that for each dividend paid on the stock during the Award Period, the amount equal to the dividend paid on the assumed number of shares held is reinvested in additional shares at a price equal to the closing market price of the stock on the ex-dividend date for the dividend, and (3) determining the final dollar value of the total assumed number of shares based on the average of the closing market prices of the stock for the period from October 1, 2025 to December 31, 2025. The "TSR" shall then equal the amount determined by subtracting $100 from the foregoing final dollar value, dividing the result by 100 and expressing the resulting fraction as a percentage.

(e) If during the Award Period any Peer Group Company enters into an agreement pursuant to which all or substantially all of the stock or assets of the Peer Group Company will be acquired by a third party (a "Signed Acquisition"), and if the Signed Acquisition is not completed by the end of the Award Period, then that company shall not be a Peer Group Company. If a Signed Acquisition of a Peer Group Company is terminated (other than in connection with the execution of another Signed Acquisition) before the end of the Award Period, then that company shall remain a Peer Group Company, and the TSR for that Peer Group Company shall be calculated as provided in Section 2.2(d), except that if the announcement of the termination of the Signed Acquisition occurs during the last three months of the Award Period, for purposes of determining the final dollar value under clause (3) of Section 2.2(d), the three-month period for which closing market prices are averaged shall be shortened to exclude any trading days preceding the announcement of the termination of the Signed Acquisition.

2.3 EPS Payout Factor.

(a) The "EPS Payout Factor" shall be determined under the table below based on the Cumulative EPS Achievement Percentage (as defined below) achieved by the Company for the Award Period:

Cumulative EPS Achievement Percentage	EPS Payout Factor
less than 93%	0%
93%	40%
100%	100%
105% or more	185%

If the Company's Cumulative EPS Achievement Percentage is between any two data points set forth in the first column of the above table, the EPS Payout Factor shall be interpolated as follows. The excess of the Company's Cumulative EPS Achievement Percentage over the Cumulative EPS Achievement Percentage of the lower data point shall be divided by the excess of the Cumulative EPS Achievement Percentage of the higher data point over the Cumulative EPS Achievement Percentage of the lower data point. The resulting fraction shall be multiplied by the difference between the EPS Payout Factors in the above table corresponding to the two data points. The product of that calculation shall be rounded to the nearest hundredth of a percentage point and then added to the EPS Payout Factor in the above table corresponding to the lower data point, and the resulting sum shall be the EPS Payout Factor.

(b) The Company's "Cumulative EPS Achievement Percentage" for the Award Period shall equal the Cumulative EPS (as defined below) divided by the Cumulative EPS Target (as defined below), expressed as a percentage and rounded to the nearest tenth of a percentage point.

(c) The Company's "Cumulative EPS" for the Award Period shall equal the sum of the Company's diluted earnings per share of common stock ("EPS") for each of the three years in the Award Period. Subject to adjustment in accordance with Section 2.5 below, the Company's diluted earnings per share of common stock for any year shall be as set forth in the audited consolidated financial statements of the Company and its subsidiaries for that year. After giving effect to any adjustments required by Section 2.5, the EPS for each year shall be rounded to the nearest penny.

(d) The Company's "Cumulative EPS Target" for the Award Period shall equal the sum of the EPS targets approved by the Committee for each of the three years in the Award Period. The EPS target for the first year of the Award Period as approved by the Committee is $____. Within the first 90 days of the second year of the Award Period, the Committee shall approve the EPS target for that year. Within the first 90 days of the third year of the Award Period, the Committee shall approve the EPS target for that year.

2.4 ROIC Performance Threshold.

(a) For purposes of this Agreement, the "ROIC Performance Threshold" shall be satisfied if the Company's Average ROIC (as defined below) for the Award Period is greater than or equal to ___%.

(b) The Company's "Average ROIC" for the Award Period shall equal the simple average of the Company's ROIC (as defined below) for each of the three years in the Award Period, rounded to the nearest hundredth of a percentage point. The Company's "ROIC" for any year shall be calculated by dividing the Company's Adjusted Net Income (as defined below) for the year by the Company's Average Long Term Capital (as defined below) for the year, and rounding the result to the nearest hundredth of a percentage point. Subject to adjustment in accordance with Section 2.5 below, the Company's "Adjusted Net Income" for any year shall be equal to the Company's net income for the year, increased by the Company's interest expense, net for the year and reduced by the Company's interest income (including net interest on deferred regulatory accounts) for the year, in each case as set forth in the Company's Annual Report on Form 10-K for that year. "Average Long Term Capital" for any year shall mean the average of the Company's Long Term Capital (as defined below) as of the last day of the year and the Company's Long Term Capital as of the last day of the prior year. Subject to adjustment in accordance with Section 2.5 below, "Long Term Capital" as of any date shall equal the sum of the Company's total shareholders' equity as of that date and the Company's long-term debt (including current maturities) as of that date, in each case as set forth on the audited consolidated balance sheet of the Company as of that date.

2.5 EPS and ROIC Adjustments. The Committee may, at any time, approve adjustments to the calculation of Cumulative EPS and/or Average ROIC to take into account such unanticipated circumstances or significant, non-recurring or unplanned events as the Committee may determine in its sole discretion, and such adjustments may increase or decrease Cumulative EPS and/or Average ROIC. Possible circumstances that may be the basis for adjustments shall include, but not be limited to, any change in applicable accounting rules or principles; any gain or loss on the disposition of a business; impairment of assets; dilution caused by Board approved business acquisition; tax changes and tax impacts of other changes; changes in applicable laws and regulations; changes in rate case timing; changes in the Company's structure; and any other circumstances outside of management's control.

3. Employment Condition.

3.1 Except as provided in Sections 3.2, 3.3 or 7.2, in order to receive a payout of Performance Shares, Recipient must be employed by the Company or any parent or subsidiary of the Company (the "Employer") on the last day of the Award Period.

3.2 If Recipient's employment by the Employer is terminated at any time prior to the end of the Award Period because of death, physical disability (within the meaning of Section 22(e)(3) of the Internal Revenue Code of 1986, as amended, and the regulations and guidance promulgated thereunder (the "Code")), or Retirement (unless such Retirement results from a termination of Recipient's employment by the Employer for Cause), Recipient shall be entitled to receive a pro-rated award. The number of Performance Shares to be issued or otherwise delivered as a pro-rated award under this Section 3.2 shall be determined by multiplying the number of Performance Shares determined under Section 2 by a fraction, the numerator of which is the number of days Recipient was employed by Employer during the Award Period and the denominator of which is the number of days in the Award Period. If Recipient's employment by the Employer terminates because of Retirement, death or physical disability and a Change in Control subsequently occurs before the end of the Award Period, the number of Performance Shares determined under Section 3.3 shall immediately be paid to Recipient. If a Change in Control occurs and Recipient's employment by the Employer subsequently terminates before the end of the Award Period because of Retirement, death or physical disability, the number of Performance Shares determined under Section 3.3 shall immediately be paid to Recipient.

3.3 CIC Acceleration.

(a) If Recipient is a party to a Change in Control Severance Agreement with the Company or a parent or subsidiary of the Company, Recipient shall immediately be paid the Target Share Amount if Recipient becomes entitled to a Change in Control Severance Benefit (as defined below). A "Change in Control Severance Benefit" means the severance benefit provided for in Recipient's Change in Control Severance Agreement with the Company or a parent or subsidiary of the Company; provided, however, that such severance benefit is a "Change in Control Severance Benefit" for purposes of this Agreement only if, under the terms of Recipient's Change in Control Severance Agreement, Recipient becomes entitled to the severance benefit (i) after a Change in Control of the Company has occurred, (ii) because Recipient's employment with the Employer has been terminated by Recipient for good reason in accordance with the terms and conditions of the Change in Control Severance Agreement or by the Employer other than for cause, and (iii) because Recipient has satisfied any other conditions or requirements specified in the Change in Control Severance Agreement and necessary for Recipient to become entitled to receive the severance benefit. For purposes of this Section 3.3(a), the terms "change in control," "good reason," "cause" and "disability" shall have the meanings set forth in Recipient's Change in Control Severance Agreement.

(b) If Recipient is not a party to a Change in Control Severance Agreement with the Company or a parent or subsidiary of the Company, Recipient shall immediately be paid the Target Share Amount if a Change in Control (as defined in Section 3.7 below) occurs and at any time after the earlier of Shareholder Approval (as defined in Section 3.8 below), if any, or the Change in Control and on or before the second anniversary of the Change in Control, (i) Recipient's employment is terminated by the Employer (or its successor) without Cause (as defined in Section 3.6 below), or (b) Recipient's employment is terminated by Recipient for Good Reason (as defined in Section 3.9 below).

3.4 If Recipient's employment by the Employer is terminated at any time prior to the end of the Award Period and Section 3.2, 3.3 or 7.2 does not apply to such termination, Recipient shall not be entitled to receive any Performance Shares.

3.5 "Retirement" shall mean termination of employment (a) on or after the first anniversary of the date of this Agreement, and (b) after Recipient is age 55 with age plus years of service (including fractions) as an employee of the Company or a parent or subsidiary of the Company totaling at least 70.

3.6 "Cause" shall mean (a) the willful and continued failure by Recipient to perform substantially Recipient's assigned duties with the Employer (other than any such failure resulting from incapacity due to physical or mental illness) after a demand for substantial performance is delivered to Recipient by the Employer which specifically identifies the manner in which Recipient has not substantially performed such duties, (b) willful commission by Recipient of an act of fraud or dishonesty resulting in economic or financial injury to the Company or Employer, (c) willful misconduct by Recipient that substantially impairs the business or reputation of the Company or Employer, or (d) willful gross negligence by Recipient in the performance of his or her duties.

3.7 For purposes of this Agreement, a "Change in Control" of the Company shall mean the occurrence of any of the following events:

(a) The consummation of:

(1) any consolidation, merger or plan of share exchange involving the Company (a "Merger") as a result of which the holders of outstanding securities of the Company ordinarily having the right to vote for the election of directors ("Voting Securities") immediately prior to the Merger do not continue to hold at least 50% of the combined voting power of the outstanding Voting Securities of the surviving corporation or a parent corporation of the surviving corporation immediately after the Merger, disregarding any Voting Securities issued to or retained by such holders in respect of securities of any other party to the Merger; or

(2) any consolidation, merger, plan of share exchange or other transaction involving Northwest Natural Gas Company ("NW Natural") as a result of which the

Company does not continue to hold, directly or indirectly, at least 50% of the outstanding securities of NW Natural ordinarily having the right to vote for the election of directors; or

(3) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all, or substantially all, the assets of the Company or NW Natural;

(b) At any time during a period of two consecutive years, individuals who at the beginning of such period constituted the Board ("Incumbent Directors") shall cease for any reason to constitute at least a majority thereof; provided, however, that the term "Incumbent Director" shall also include each new director elected during such two-year period whose nomination or election was approved by two-thirds of the Incumbent Directors then in office; or

(c) Any person (as such term is used in Section 14(d) of the Securities Exchange Act of 1934, other than the Company or any employee benefit plan sponsored by the Company or NW Natural) shall, as a result of a tender or exchange offer, open market purchases or privately negotiated purchases from anyone other than the Company, have become the beneficial owner (within the meaning of Rule 13d-3 under the Securities Exchange Act of 1934), directly or indirectly, of Voting Securities representing twenty percent (20%) or more of the combined voting power of the then outstanding Voting Securities, but disregarding any Voting Securities with respect to which that acquirer has filed SEC Schedule 13G indicating that the Voting Securities were not acquired and are not held for the purpose of or with the effect of changing or influencing, directly or indirectly, the Company's management or policies, unless and until that entity or person files SEC Schedule 13D, at which point this exception will not apply to such Voting Securities, including those previously subject to a SEC Schedule 13G filing.

3.8 For purposes of this Agreement, "Shareholder Approval" shall be deemed to have occurred if the shareholders of the Company approve an agreement entered into by the Company, the consummation of which would result in the occurrence of a Change in Control.

3.9 For purposes of this Agreement, "Good Reason" shall mean the occurrence after Shareholder Approval, if applicable, or the Change in Control, of any of the following circumstances, but only if (x) Recipient gives notice to Employer of Recipient's intent to terminate employment for Good Reason within 30 days after the later of (1) notice to Recipient of such circumstances, or (2) the Change in Control, and (y) such circumstances are not fully corrected by the Employer within 90 days after Recipient's notice:

(a) the assignment to Recipient of a different title, job or responsibilities that results in a decrease in the level of Recipient's responsibility; provided that Good Reason shall not exist if Recipient continues to have the same or a greater general level of responsibility for the former Employer operations after the Change in Control as Recipient had prior to the Change in Control even though such responsibilities have necessarily changed due to the former Employer operations becoming a subsidiary or division of the surviving company;

(b) a reduction by the Employer in Recipient's base salary as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control;

(c) the failure by Employer to continue in effect any employee benefit or incentive plan in which Recipient is participating immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control (or plans providing Recipient with at least substantially similar benefits) other than as a result of the normal expiration of any such plan in accordance with its terms as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control, or the taking of any action, or the failure to act, by Employer which would adversely affect Recipient's continued participation in any of such plans on at least as favorable a basis to Recipient as is the case immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control or which would materially reduce Recipient's benefits in the future under any of such plans or deprive Recipient of any material benefit enjoyed by Recipient immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control;

(d) the failure by the Employer to provide and credit Recipient with the number of paid vacation days to which Recipient is then entitled in accordance with the Employer's normal vacation policy as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control; or

(e) the Employer's requiring Recipient to be based more than 25 miles from where Recipient's office is located immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control except for required travel on the Employer's business to an extent substantially consistent with the business travel obligations which Recipient undertook on behalf of the Employer prior to the earlier of Shareholder Approval, if applicable, or the Change in Control.

4. Dividend Equivalent Cash Award. The amount of the Dividend Equivalent Cash Award shall be determined by multiplying the number of Performance Shares deliverable to Recipient as determined under Sections 2 and 3 by the total amount of dividends paid per share of the Company's Common Stock for which the dividend record date occurred after the beginning of the Award Period and before the date of delivery of the Performance Shares.

5. Certification and Payment. At the regularly scheduled meeting of the Committee held in February of the year immediately following the final year of the Award Period (the "Certification Meeting"), the Committee shall review the Company's results for the Award Period. Prior to the Certification Meeting, the Company shall calculate the number of Performance Shares deliverable and the amount of the Dividend Equivalent Cash Award payable to Recipient, and shall submit these calculations to the Committee. At or prior to the Certification Meeting, the Committee shall certify in writing (which may consist of approved minutes of the Certification Meeting) the number of Performance Shares deliverable to Recipient and the amount of the Dividend Equivalent Cash Award payable to Recipient. Subject to applicable tax withholding, the amounts so certified shall be delivered or paid (as applicable) on a date (the "Payment Date") that is the later of March 1, 2026 or five business days following the Certification Meeting, and no amounts shall be delivered or paid prior to certification. No fractional shares shall be delivered and the number of Performance Shares deliverable shall be rounded to the nearest whole share. Notwithstanding the foregoing, if Recipient shall have made a valid election to defer receipt of Performance Shares or the Dividend Equivalent Cash Award pursuant to the terms of Northwest Natural's Deferred Compensation Plan for Directors and Executives (the "DCP"), payment of the award shall be made in accordance with that election.

6. Tax Withholding. Recipient acknowledges that, on the Payment Date when the Performance Shares are issued or otherwise delivered to Recipient, the Value (as defined below) on that date of the Performance Shares (as well as the amount of the Dividend Equivalent Cash Award) will be treated as ordinary compensation income for federal and state income and FICA tax purposes, and that the Employer will be required to withhold taxes on these income amounts. To satisfy the required withholding amount, the Employer shall first withhold all or part of the Dividend Equivalent Cash Award, and if that is insufficient, the Employer shall withhold the number of Performance Shares having a Value equal to the remaining withholding amount. For purposes of this Section 6, the "Value" of a Performance Share shall be equal to the closing market price for Company Common Stock on the last trading day preceding the date on which the Share is treated for federal income tax purposes as transferred to Recipient. Notwithstanding the foregoing, Recipient may elect not to have Performance Shares withheld to cover taxes by

giving notice to the Company in writing prior to the Payment Date, in which case the Performance Shares shall be issued or acquired in the Recipient's name on the Payment Date thereby triggering the tax consequences, but the Company shall retain the certificate for the Performance Shares as security until Recipient shall have paid to the Company in cash any required tax withholding not covered by withholding of the Dividend Equivalent Cash Award. If the Employer is required to withhold FICA taxes with respect to the Performance Shares prior to the time the shares underlying the Performance Shares otherwise become payable, Recipient shall, immediately upon notification of the amount due, pay to the Company in cash or by check amounts necessary to satisfy applicable FICA withholding requirements. If Recipient fails to pay the amount demanded, the Company may withhold that amount from other amounts payable to Recipient, including salary, subject to applicable law. Alternatively, the Employer may, in its sole discretion, choose to treat the FICA withholding as a loan to Recipient on terms determined by the Employer and communicated to Recipient.

7. Sale of the Company. If there shall occur before the Payment Date a merger, consolidation or plan of exchange involving the Company pursuant to which the outstanding shares of Common Stock of the Company are converted into cash or other stock, securities or property, or a sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all, or substantially all, the assets of the Company (either, a "Company Sale"), then either:

7.1 the unvested Performance Shares shall be converted into restricted stock units for stock of the surviving or acquiring corporation in the applicable transaction using the exchange rate, if any, used in determining shares of the surviving corporation to be held by the former holders of the Company's Common Stock following the applicable transaction, or, if there was no exchange rate, taking into account the relative values of the companies involved in the applicable transaction, and disregarding fractional shares with the amount and type of shares subject thereto to be conclusively determined by the Committee; ; or

7.2 a pro rata number of Performance Shares and the related dividend equivalent cash payment shall be delivered simultaneously with the closing of the applicable transaction such that Recipient will participate as a shareholder in receiving proceeds from such transaction with respect to those shares. The number of Performance Shares to be delivered as a pro-rated award under this Section 7.2 shall be determined by multiplying the Target Share Amount by a fraction, the numerator of which is the number of days of the Award Period elapsed prior to the closing of the transaction and the denominator of which is the number of days in the Award Period.

8. Changes in Capital Structure. If the outstanding Common Stock of the Company is hereafter increased or decreased or changed into or exchanged for a different number or kind of shares or other securities of the Company by reason of any stock split, combination of shares or dividend payable in shares, recapitalization or reclassification, appropriate adjustment shall be made by the Committee in the number and kind of shares subject to this Agreement so that the Recipient's proportionate interest before and after the occurrence of the event is maintained.

9. Recoupment On Misconduct.

9.1 If at any time before a Change in Control and within three years after the Payment Date, the Committee determines that Recipient engaged in any Misconduct (as defined below) during the Award Period that contributed to an obligation to restate the Company's financial statements for any quarter or year in the Award Period or that otherwise has had (or will have when publicly disclosed) an adverse impact on the Company's common stock price, Recipient shall repay to the Company the Excess LTIP Compensation (as defined below). The term "Excess LTIP Compensation" means the excess of (a) the number of Performance Shares and the amount of the Dividend Equivalent Cash Award as originally calculated and certified under Section 5 of this Agreement, over (b) the number of Performance Shares and the amount of the Dividend Equivalent Cash Award as recalculated (1) for the TSR Modifier, assuming that the average of the closing market prices of the Company's common stock for the period from October 1, 2025 to December 31, 2025 was an amount determined appropriate by the Committee in its discretion to reflect what the Company's common stock price would have been if the restatement had occurred or other Misconduct had been disclosed prior to October 1, 2025, and (2) for the EPS Payout Factor and the ROIC Performance Threshold, based on the Company's financial statements for all years of the Award Period as restated. The Committee may, in its sole discretion, reduce the amount of Excess LTIP Compensation to be repaid by Recipient to take into account the tax consequences of such repayment or any other factors. If any Performance Shares included in the Excess LTIP Compensation are sold by Recipient prior to the Company's demand for repayment (including any shares withheld for taxes under Section 6 of this Agreement), Recipient shall repay to the Company 100% of the proceeds of such sale or sales. The return of Excess LTIP Compensation is in addition to and separate from any other relief available to the Company due to Recipient's Misconduct.

9.2 "Misconduct" shall mean (a) willful commission by Recipient of an act of fraud or dishonesty resulting in economic or financial injury to the Company, (b) willful misconduct by Recipient that substantially impairs the Company's business or reputation, or (c) willful gross negligence by Recipient in the performance of his or her duties.

9.3 If any portion of the Performance Shares or the Dividend Equivalent Cash Award was deferred under the DCP, the Excess LTIP Compensation shall first be recovered by canceling all or a portion of the amounts so deferred under the DCP and any dividends or other earnings credited under the DCP with respect to such cancelled amounts. The Company may seek direct repayment from Recipient of any Excess LTIP Compensation not so recovered and may, to the extent permitted by applicable law, offset such Excess LTIP Compensation against any compensation or other amounts owed by the Company to Recipient. In particular, Excess LTIP Compensation may be recovered by offset against the after-tax proceeds of deferred compensation payouts under the DCP, Northwest Natural's Executive Supplemental Retirement Income Plan or Northwest Natural's Supplemental Executive Retirement Plan at the times such deferred compensation payouts occur under the terms of those plans. Excess LTIP Compensation that remains unpaid for more than 60 days after demand by the Company shall accrue interest at the rate used from time to time for crediting interest under the DCP.

9.4 Notwithstanding the foregoing, if after the date of this Agreement the Company adopts a "claw-back" or similar policy, that policy as in effect at time the malfeasance is discovered by the Company triggering a claw-back shall supersede Sections 9.1 through 9.3 and shall be binding on Recipient.

10. Approvals. The obligations of the Company under this Agreement are subject to the approval of state and federal authorities or agencies with jurisdiction in the matter. The Company will use its best efforts to take steps required by state or federal law or applicable regulations, including rules and regulations of the Securities and Exchange Commission and any stock exchange on which the Company's shares may then be listed, in connection with the award under this Agreement. The foregoing notwithstanding, the Company shall not be obligated to issue or deliver Common Stock under this Agreement if such issuance or delivery would violate applicable state or federal law.

11. No Right to Employment. Nothing contained in this Agreement shall confer upon Recipient any right to be employed by the Employer or to continue to provide services to the Employer or to interfere in any way with the right of the Employer to terminate Recipient's services at any time for any reason, with or without cause.

12. Miscellaneous.

12.1 Entire Agreement; Amendment. This Agreement constitutes the entire agreement of the parties with regard to the subjects hereof and may be amended only by written agreement between the Company and Recipient.

12.2 Notices. Any notice required or permitted under this Agreement shall be in writing and shall be deemed sufficient when delivered personally to the party to whom it is addressed or when deposited into the United States Mail as registered or certified mail, return receipt requested, postage prepaid, addressed to the Company, Attention: Corporate Secretary, at 250 SW Taylor Street, Portland, Oregon 97204 or to Employer, Attention: Corporate Secretary, at its principal executive offices, or to Recipient at the address of Recipient in the Company's records, or at such other address as such party may designate by ten (10) days' advance written notice to the other party.

12.3 Assignment; Rights and Benefits. Recipient shall not assign this Agreement or any rights hereunder to any other party or parties without the prior written consent of the Company. The rights and benefits of this Agreement shall inure to the benefit of and be enforceable by the Company's successors and assigns and, subject to the foregoing restriction on assignment, be binding upon Recipient's heirs, executors, administrators, successors and assigns.

12.4 Further Action. The parties agree to execute such further instruments and to take such further action as may reasonably be necessary to carry out the intent of this Agreement.

12.5 Applicable Law; Attorneys' Fees. The terms and conditions of this Agreement shall be governed by the laws of the State of Oregon. In the event either party institutes litigation hereunder, the prevailing party shall be entitled to reasonable attorneys' fees to be set by the trial court and, upon any appeal, the appellate court.

12.6 Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original.

13. Section 409A.

13.1 The intent of the parties is that payments and benefits under this Agreement comply with Section 409A of the Code ("Section 409A"), to the extent subject thereto, or otherwise be exempt from Section 409A, and accordingly, to the maximum extent permitted, this Agreement shall be interpreted and administered to be exempt from or in compliance therewith. Each amount to be paid or benefit to be provided under this Agreement shall be construed as a separate and distinct payment for purposes of Section 409A. Without limiting the foregoing and notwithstanding anything contained herein to the contrary, to the extent required to avoid accelerated taxation and/or tax penalties under Section 409A:

(a) Recipient shall not be considered to have terminated employment with the Company for purposes of any payments under this Agreement which are subject to Section 409A until Recipient would be considered to have incurred a "separation from service" from the Company within the meaning of Section 409A;

(b) Amounts that would otherwise be payable and benefits that would otherwise be provided pursuant to this Agreement or any other arrangement between Recipient and the Company during the six (6) month period immediately following Recipient's separation from service shall instead be paid on the first business day after the date that is six (6) months following Recipient's separation from service (or, if earlier, Recipient's date of death);

(c) Any payment that will be in compliance with Section 409A only if payable under designations permitted by Treas. Reg. Section 1.409A-3(c), or only if payable upon termination of a deferred compensation plan pursuant to Treas. Reg. Section 1.409A-3(j)(iv), shall be made only in compliance with such regulations;

(d) Any payment that will be in compliance with Section 409A only if payable upon a change in control event within the meaning Treas. Reg. Section 1.409A-3(i)(5) shall be made only in compliance with such regulation; and

(e) If any severance amount payable under any other agreement that Recipient may have a right or entitlement to as of the date of this Agreement constitutes deferred compensation under Section 409A, then the portion of the benefits payable hereunder equal to such other amount shall instead be provided in the form set forth in such other agreement.

13.2 The Company makes no representation that any or all of the payments described in this Agreement will be exempt from or comply with Section 409A and makes no undertaking to preclude Section 409A from applying to any such payment. Recipient understands and agrees that Recipient shall be solely responsible for the payment of any taxes, penalties, interest or other expenses incurred by Recipient on account of non-compliance with Section 409A.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the day and year first above written.

NORTHWEST NATURAL HOLDING COMPANY

By ______________________________

Title ______________________________

RECIPIENT

____

EXHIBIT A
Peer Group Companies

Atmos Energy Corporation
ONE Gas, Inc.
South Jersey Industries, Inc.
Spire Inc.
Southwest Gas Holdings, Inc.
NiSource Inc.
New Jersey Resources Corporation
Avista Corporation
Black Hills Corporation
MGE Energy, Inc.
NorthWestern Corporation
Unitil Corporation

SUBSIDIARIES OF NORTHWEST NATURAL HOLDING COMPANY

an Oregon Corporation

Name of Subsidiary	Jurisdiction Organized
Northwest Natural Gas Company (dba NW Natural)	**Oregon**
Northwest Energy Corporation(1)	Oregon
NWN Gas Reserves LLC(1)	Oregon
NW Natural RNG Holding Company, LLC(1)	Oregon
Lexington Renewable Energy LLC(1)	Delaware
Dakota City Renewable Energy LLC(1)	Delaware
NW Natural Energy, LLC	Oregon
NW Natural Gas Storage, LLC	Oregon
NNG Financial Corporation	Oregon
Northwest Biogas, LLC	Oregon
KB Pipeline Company	Oregon
NW Natural Water Company, LLC	Oregon
Salmon Valley Water Company	Oregon
NW Natural Water of Oregon, LLC	Oregon
Sunstone Water, LLC	Oregon
Sunstone Infrastructure, LLC	Oregon
Sunriver Water LLC	Oregon
Sunriver Environmental LLC	Oregon
Avion Water Company, Inc.	Oregon
NW Natural Renewables Holdings, LLC	Oregon
NW Natural Ohio Renewable Energy, LLC	Oregon
NW Natural Water of Washington, LLC	Washington

Cascadia Water, LLC	Washington
Cascadia Infrastructure, LLC	Washington
Suncadia Water Company, LLC	Washington
Suncadia Environmental Company, LLC	Washington
NW Natural Water of Idaho, LLC	Idaho
Falls Water Co., Inc.	Idaho
Gem State Water Company, LLC	Idaho
Gem State Infrastructure, LLC	Idaho
NW Natural Water of Texas, LLC	Texas
Blue Topaz Water, LLC	Texas
Blue Topaz Infrastructure, LLC	Texas
T & W Water Service Company (dba Blue Topaz Utilities)	Texas
NW Natural Water of Arizona, LLC	Oregon
Foothills Water & Sewer, LLC (dba Foothills Utilities)	Arizona
Turquoise Infrastructure, LLC	Oregon
NW Natural Water of California, LLC	Oregon
Blue Diamond Water Company, LLC	California
Blue Diamond Infrastructure, LLC	Oregon
NW Natural Water Services, LLC	Oregon

(1) Subsidiary of Northwest Natural Gas Company

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (Nos. 333-187005-01, 333-180350-01, 333-134973-01, 333-139819-01, 333-221347-01, 333-227687, 333-234539, and 333-266517) and Form S-3 (No. 333-258792) of Northwest Natural Holding Company of our report dated February 24, 2023 relating to the financial statements, financial statement schedules and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Portland, Oregon
February 24, 2023

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (No. 333-214425) and Form S-3 (No. 333-258792-01) of Northwest Natural Gas Company of our report dated February 24, 2023 relating to the financial statements and financial statement schedule which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Portland, Oregon
February 24, 2023

EXHIBIT 31.1

CERTIFICATION

I, David H. Anderson, certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2022 of Northwest Natural Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2023

/s/ David H. Anderson
David H. Anderson
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Frank H. Burkhartsmeyer, certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2022 of Northwest Natural Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2023

/s/ Frank H. Burkhartsmeyer
Frank H. Burkhartsmeyer
Senior Vice President and Chief Financial Officer

EXHIBIT 31.3

CERTIFICATION

I, David H. Anderson, certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2022 of Northwest Natural Holding Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2023

/s/ David H. Anderson
David H. Anderson
President and Chief Executive Officer

EXHIBIT 31.4

CERTIFICATION

I, Frank H. Burkhartsmeyer, certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2022 of Northwest Natural Holding Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 24, 2023

/s/ Frank H. Burkhartsmeyer
Frank H. Burkhartsmeyer
Senior Vice President and Chief Financial Officer

EXHIBIT 32.1

NORTHWEST NATURAL GAS COMPANY

Certificate Pursuant to Section 906
of Sarbanes – Oxley Act of 2002

Each of the undersigned, DAVID H. ANDERSON, Chief Executive Officer, and FRANK H. BURKHARTSMEYER, the Chief Financial Officer, of NORTHWEST NATURAL GAS COMPANY (the Company), DOES HEREBY CERTIFY that:

1. The Company's Annual Report on Form 10-K for the year ended December 31, 2022 (the Report) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. Information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

IN WITNESS WHEREOF, each of the undersigned has caused this instrument to be executed this twenty-fourth day of February 2023.

/s/ David H. Anderson
David H. Anderson
President and Chief Executive Officer

/s/ Frank H. Burkhartsmeyer
Frank H. Burkhartsmeyer
Senior Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002 has been provided to Northwest Natural Gas Company and will be retained by Northwest Natural Gas Company and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.2

NORTHWEST NATURAL HOLDING COMPANY

Certificate Pursuant to Section 906
of Sarbanes – Oxley Act of 2002

Each of the undersigned, DAVID H. ANDERSON, Chief Executive Officer, and FRANK H. BURKHARTSMEYER, the Chief Financial Officer, of NORTHWEST NATURAL HOLDING COMPANY (the Company), DOES HEREBY CERTIFY that:

1. The Company's Annual Report on Form 10-K for the year ended December 31, 2022 (the Report) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. Information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

IN WITNESS WHEREOF, each of the undersigned has caused this instrument to be executed this twenty-fourth day of February 2023.

/s/ David H. Anderson
David H. Anderson
President and Chief Executive Officer

/s/ Frank H. Burkhartsmeyer
Frank H. Burkhartsmeyer
Senior Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002 has been provided to Northwest Natural Holding Company and will be retained by Northwest Natural Holding Company and furnished to the Securities and Exchange Commission or its staff upon request.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2022.
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________.
Commission file number 001-36108

ONE Gas, Inc.

(Exact name of registrant as specified in its charter)

Oklahoma	**46-3561936**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
15 East Fifth Street Tulsa, OK	**74103**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code **(918) 947-7000**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol	Name of exchange on which registered
Common Stock, par value $0.01 per share	OGS	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The aggregate market value of the equity securities held by nonaffiliates based on the closing trade price of the registrant on June 30, 2022, was $4.2 billion.

On February 17, 2023, we had 55,350,277 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:
Portions of the definitive proxy statement to be delivered to shareholders in connection with the Annual Meeting of Shareholders to be held May 25, 2023, are incorporated by reference in Part III.

ONE Gas, Inc.
2022 ANNUAL REPORT

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As used in this Annual Report, references to "we," "our," "us" or the "Company" refer to ONE Gas, Inc., an Oklahoma corporation, and its predecessors and subsidiaries, unless the context indicates otherwise.

GLOSSARY

The abbreviations, acronyms and industry terminology used in this Annual Report are defined as follows:

AAO	Accounting Authority Order
ADIT	Accumulated deferred income taxes
AFUDC	Allowance for funds used during construction
Annual Report	Annual Report on Form 10-K for the year ended December 31, 2022
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Bcf	Billion cubic feet
CAA	Federal Clean Air Act, as amended
CERCLA	Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFTC	Commodities Futures Trading Commission
CISA	Cybersecurity and Infrastructure Security Agency
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
CNG	Compressed natural gas
Code	Internal Revenue Code of 1986, as amended
COSA	Cost-of-Service Adjustment
COVID-19	Coronavirus Disease 2019
DART	Days Away, Restricted or Transferred Incident Rate; calculated by multiplying the total number of recordable injuries and illnesses, or one or more restricted days that resulted in an employee transferring to a different job within the company by 200,000, and then dividing that number by the total number of hours worked by all employees
DHS	United States Department of Homeland Security
DOT	United States Department of Transportation
Dth	Dekatherm
ECP	The ONE Gas, Inc. Amended and Restated Equity Compensation Plan (2018)
EDIT	Excess accumulated deferred income taxes resulting from a decrease in enacted tax rates
EPA	United States Environmental Protection Agency
EPS	Earnings per share
ERT	Emergency Response Time; calculated as the time between the creation of an emergency order and the arrival of a first company responder to the scene expressed as the percentage of emergency orders with a response time of 30 minutes or less
ESG	Environmental, social and governance
ESPP	The ONE Gas, Inc. Amended and Restated Employee Stock Purchase Plan
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States of America
GRIP	Texas Gas Reliability Infrastructure Program
GSRS	Gas System Reliability Surcharge
HCA(s)	High consequence area(s)
HDD	Heating degree day is a measure designed to reflect the demand for energy needed for heating based on the extent to which the daily average temperature falls below a reference temperature for which no heating is required, usually 65 degrees Fahrenheit
IRA of 2022	Inflation Reduction Act of 2022
IT	Information technology
KCC	Kansas Corporation Commission
KDHE	Kansas Department of Health and Environment
KGSS-I	Kansas Gas Service Securitization I, L.L.C.
LDC	Local distribution company
LIBOR	London Interbank Offered Rate
MAOP(s)	Maximum allowable operating pressure(s)
MGP	Manufactured gas plant
MMcf	Million cubic feet

Moody's	Moody's Investors Service, Inc.
NPRM	Notice of proposed rulemaking
NYSE	New York Stock Exchange
OCC	Oklahoma Corporation Commission
ODFA	Oklahoma Development Finance Authority
ONE Gas	ONE Gas, Inc.
ONE Gas 2021 Term Loan Facility	ONE Gas' $2.5 billion two-year unsecured term loan facility, dated February 22, 2021, which terminated on March 11, 2021
ONE Gas 364-day Credit Agreement	ONE Gas' $250 million 364-day revolving credit agreement, dated April 7, 2020, which terminated on March 16, 2021
ONE Gas Credit Agreement	ONE Gas' $1.0 billion revolving credit agreement, as amended
OSHA	Occupational Safety and Health Administration
PBRC	Performance-Based Rate Change
PHMSA	United States Department of Transportation Pipeline and Hazardous Materials Safety Administration
Pipeline Safety, Regulatory Certainty and Job Creation Act	Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, as amended
PIPES Act	Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020
PPE	Personal protective equipment
PVIR	Preventable Vehicle Incident Rate; calculated by multiplying the number of total preventable vehicle incidents by 1,000,000 and then dividing that number by the total number of business use miles driven
Quarterly Report(s)	Quarterly Report(s) on Form 10-Q
RNG	Renewable natural gas
ROE	Return on equity calculated consistent with utility ratemaking principles in each jurisdiction in which we operate
RRC	Railroad Commission of Texas
S&P	Standard and Poor's Rating Services
SEC	Securities and Exchange Commission
Securities Act	Securities Act of 1933, as amended
Securitized Utility Tariff Bonds	Series 2022-A Senior Secured Securitized Utility Tariff Bonds, Tranche A
Securitized Utility Tariff Property	Securitized Utility Tariff Property as defined in the financing order issued by the KCC in August 2022
Senior Notes	ONE Gas' registered notes consisting of $300 million of 3.61 percent senior notes due February 2024, $473 million of 1.10 percent senior notes due March 2024, $300 million of 2.00 percent senior notes due May 2030, $300 million of 4.25 percent senior notes due September 2032, $600 million of 4.66 percent senior notes due February 2044 and $400 million of 4.50 percent senior notes due November 2048
SOFR	Secured Overnight Financing Rate administered by the Federal Reserve Bank of New York
TCEQ	Texas Commission on Environmental Quality
TPFA	Texas Public Finance Authority
TSA	United States Department of Homeland Security's Transportation Security Administration
TRIR	Total Recordable Incident Rate; calculated by multiplying the number of recordable cases by 200,000, and then dividing that number by the number of hours worked by all employees
WNA	Weather normalization adjustment(s)
XBRL	eXtensible Business Reporting Language

The statements in this Annual Report that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements. Forward-looking statements may include words such as "will," "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "should," "goal," "forecast," "guidance," "could," "may," "continue," "might," "potential," "scheduled," "likely" and other words and terms of similar meaning. Although we believe that our expectations regarding future events are based on reasonable assumptions, we can give no assurance that such expectations and assumptions will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements are *described under Part I, Item 1A, Risk Factors, and Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation, Forward-Looking Statements, in this Annual Report.*

PART I.

ITEM 1. BUSINESS

OUR BUSINESS

ONE Gas, Inc. is incorporated under the laws of the state of Oklahoma. Our common stock is listed on the NYSE under the trading symbol "OGS," and is included in the S&P MidCap 400 Index. We are a 100-percent regulated natural gas distribution utility, headquartered in Tulsa, Oklahoma, and one of the largest publicly traded natural gas utilities in the United States. We are the successor to the company founded in 1906 as Oklahoma Natural Gas Company, which became ONEOK, Inc. (NYSE: OKE) in 1980. On January 31, 2014, ONE Gas officially separated from ONEOK, Inc.

We provide natural gas distribution services to approximately 2.3 million customers and are the largest natural gas distributor in Oklahoma and Kansas and the third largest in Texas, in terms of customers. We primarily serve residential, commercial and transportation customers in all three states. Our largest natural gas distribution markets in terms of customers are Oklahoma City and Tulsa, Oklahoma; Kansas City, Wichita and Topeka, Kansas; and Austin and El Paso, Texas. Our three divisions, Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service, distribute natural gas to approximately 88 percent, 71 percent and 13 percent of the natural gas distribution customers in Oklahoma, Kansas and Texas, respectively.

OUR STRATEGY

Our mission is to deliver natural gas for a better tomorrow. Our business strategy is focused on:

- Safe and Reliable Energy - We are committed, first and foremost, to pursuing a zero-incident safety and 100-percent compliance culture. A significant portion of our capital spending is focused on the safety, integrity and reliability of our natural gas distribution system. We also deploy a variety of operational and damage prevention procedures and technologies to monitor and maintain our natural gas distribution system. Our Company's focus on safety also extends to protecting our assets and information systems from physical damage and cyber intrusions.

- A High-performing Workforce - Our employees are the foundation of our Company. Our success begins with a values-driven culture and a commitment to engaging people to do their best work in an inclusive environment.

- Capital Demand Growth - Through capital investments, we meet growing customer demand, support economic development, and manage our system investments for the long-term.

- Clean Energy Solutions - Our assets are essential to a clean energy future. We are focused on reducing our emissions and supporting our customers' emission reduction efforts.

- Serving Customers - We provide reliable and affordable energy to our customers by efficiently managing our resources and leveraging technology solutions to enhance operational efficiency. Our energy efficiency and education programs help our customers invest in higher efficiency appliances and reduce energy usage. For customers needing assistance, we offer payment arrangement options and seek to connect customers to social service agencies that provide financial assistance.

REGULATORY OVERVIEW

We are subject to regulation and oversight of the state and local regulatory authorities of the territories in which we operate. Rates and charges for natural gas distribution services are established by the OCC for Oklahoma Natural Gas and by the KCC for Kansas Gas Service. Rates and charges in the incorporated cities of our service areas in Texas are established by those cities, which have primary jurisdiction for their respective service areas. Rates and charges in the unincorporated areas of our service territory in Texas are established by the RRC. All appellate matters in Texas are subject to regulatory oversight by the RRC. These regulatory authorities have the responsibility of ensuring that the utilities under their jurisdiction provide safe and reliable service at a reasonable cost, while providing utilities the opportunity to earn a fair and reasonable return on their investments.

Generally, our rates and charges are established in rate case proceedings. Regulatory authorities may also approve mechanisms that allow for adjustments between rate cases for investments made or specific costs incurred. Due to the nature of the regulatory process, there is an inherent lag between the time that we make investments or incur additional costs and the setting of new rates and/or charges to recover those investments or costs. Additionally, we are not allowed recovery of certain costs we incur.

The following provides additional detail on the regulatory mechanisms in the jurisdictions we serve.

Oklahoma - Oklahoma Natural Gas currently operates under a PBRC mechanism, which provides for streamlined annual rate reviews between rate cases to adjust rates for incremental capital investment and changes in revenue and allowed expenses. Under this mechanism, we have an authorized ROE of 9.4 percent, with a 100 basis point dead-band of 8.9 to 9.9 percent. If our achieved ROE is below 8.9 percent, our base rates are increased upon OCC approval to an amount necessary to restore the ROE to 9.4 percent. If our achieved ROE exceeds 9.9 percent, the portion of the earnings that exceeds 9.9 percent is shared with our customers, who receive the benefit of 75 percent of those earnings. We retain the benefit of the remaining 25 percent. Oklahoma Natural Gas is required to make filings pursuant to the PBRC mechanism for the 12 months ended December 31 for each of the years 2021 through 2025. Oklahoma Natural Gas is also required to file a rate case on or before June 30, 2027, based on a test year ending December 31, 2026.

Kansas - Kansas Gas Service files periodic rate cases with the KCC as needed. Between rate cases, Kansas Gas Service adjusts rates through provisions of the GSRS statute. The GSRS statute allows Kansas Gas Service to file for a rate adjustment providing a recovery of and return on qualifying infrastructure investments incurred between rate case filings, including safety-related investments to replace, upgrade or modernize obsolete facilities, as well as projects that enhance the integrity of pipeline system components or extend the useful life of such assets. Eligible investments also include expenditures for relocations and physical and cyber security. Filings cannot occur more often than once every 12 months and the rate adjustment cannot increase the monthly charge by more than $0.80 per residential customer per month compared with the most recent GSRS filing. Rate adjustments reflected in the GSRS surcharge may only be collected for 60 months before Kansas Gas Service is required to file a rate case or cease collection of the surcharge. A full rate case may be filed at shorter intervals if desired by either Kansas Gas Service or the KCC.

Texas - Texas Gas Service provides service to customers in various service areas. These service areas are further divided into incorporated cities and unincorporated areas. Periodic rate cases are filed with cities or the RRC, as needed. Between rate cases, Texas Gas Service can adjust rates through annual filings pursuant to the GRIP statute or a COSA filing. In 2022, Texas Gas Service’s customers were aggregated in five service areas. Effective February 2023, three of these service areas were consolidated, reducing the total number of service areas to three.

Annual filings under the GRIP statute allow Texas Gas Service to recover depreciation, taxes, and a return on the annual net increase in investment for a service area. After the fifth anniversary of the effective date of the rate schedules from the first GRIP filing for a service area, Texas Gas Service is required to file a full rate case. A full rate case may be filed at shorter intervals if desired by either Texas Gas Service or the regulator. In 2022, Texas Gas Service made annual GRIP filings for the incorporated cities in two of its service areas and for the unincorporated areas in all five service areas, which combined comprise 91 percent of Texas Gas Service’s customers.

COSA tariffs permit Texas Gas Service to recover depreciation, taxes, and a return on the annual increases in net investment, and adjust rates for annual increases or decreases in certain expenses and revenues. The various COSAs have a cap on the increase in expenses. A full rate case may be filed when desired by Texas Gas Service or the regulatory authority but is not required. Texas Gas Service makes an annual COSA filing for the incorporated cities in one of its service areas, comprising 9 percent of its customers.

Weather normalization - All of our service areas utilize weather normalization mechanisms. These mechanisms are designed to reduce the delivery charge component of customers’ bills for the additional volumes used when actual HDDs exceed normalized HDDs and to increase the delivery charge component of customers’ bills for the reduction in volumes used when actual HDDs are less than normal HDDs. Normal HDDs are established through rate proceedings in each of our jurisdictions.

The following tables provide additional detail on our rate structures and the regulatory mechanisms in each of our jurisdictions:

Division	Jurisdiction	Effective Date of Last Action(1)	Rate Base (millions)	Pre-Tax Rate of Return	Equity Ratio	ROE
Oklahoma Natural Gas (2)	Oklahoma	November 2022	$1,854	8.95%	59%	9.40%
Kansas Gas Service (3)	Kansas	November 2022	$1,261	8.60%	N/A	9.30%
Texas Gas Service (2)	Central-Gulf	June 2022	$617	8.95%	59%	9.50%
	West-North(7)	February 2023	$589	8.91%	60%	9.60%
	Rio Grande Valley	August 2022	$160	8.89%	61%	9.50%

Division	Jurisdiction	Interim Rate Adjustment Mechanism	Interim Capital Recovery	WNA	WNA Effective Dates	Energy Efficiency / Conservation Program
Oklahoma Natural Gas	Oklahoma	PBRC	Yes	Yes	November - April	Yes
Kansas Gas Service (3)	Kansas	GSRS	Yes	Yes	January - December	No
Texas Gas Service	Central-Gulf	GRIP	Yes	Yes	September - May	Yes
	West-North	GRIP	Yes	Yes	September - May	No
	Rio Grande Valley	GRIP / COSA	Yes	Yes	September - May	Yes

Division	Jurisdiction	Purchased Gas Adjustment(4)	Bad Debt Recovery(5)	Expense Trackers(6)
Oklahoma Natural Gas	Oklahoma	Yes	Yes	N/A
Kansas Gas Service (3)	Kansas	Yes	Yes	Yes
Texas Gas Service	Central-Gulf	Yes	Yes	Yes
	West-North	Yes	Yes	Yes
	Rio Grande Valley	Yes	Yes	Yes

(1) Effective date of last approved rate case or interim filing.
(2) The rate base, authorized ROE, authorized debt/equity ratio and authorized return on equity presented in this table are those from the most recent approved regulatory filing for Oklahoma Natural Gas and Texas Gas Service.
(3) Kansas Gas Service's most recent rate case, approved in February 2019, settled without a determination of rate base, ROE, authorized debt/equity ratio and authorized return on equity. This reflects Kansas Gas Service's estimate of rate base from that rate case adjusted for approved GSRS filings and ROE embedded in the pre-tax carrying charge utilized in its GSRS filing.
(4) Our purchased gas adjustment mechanisms allow recovery of expenses the Company incurs to purchase, transport, and store natural gas for our customers. These costs are passed on to customers without markup.
(5) We recover the gas cost portion of bad debts through our various purchased gas adjustment mechanisms.
(6) Expense trackers include pension and other postemployment benefits costs for Kansas Gas Service and Texas Gas Service, ad-valorem taxes in Kansas and pipeline integrity testing expenses in Texas.
(7) Effective February 1, 2023, the West Texas, North Texas and Borger/Skellytown service areas were consolidated into the West-North service area.

Our natural gas sales include fixed and variable charges related to the delivery of natural gas and gas costs that are passed through to our customers in accordance with our cost of natural gas regulatory mechanisms. Fixed charges reflect the portion of our natural gas sales attributable to the monthly fixed customer charge component of our rates, which does not fluctuate based on customer usage in each period. Variable charges reflect the portion of our natural gas sales that fluctuate with the volumes delivered and billed and the effects of weather normalization.

For the year ended December 31, 2022, approximately 88 percent, 56 percent, and 69 percent of our revenues from sales customers, excluding the cost of natural gas, were recovered from fixed charges for Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service, respectively.

MARKET CONDITIONS AND SEASONALITY

Supply - We purchased 165 Bcf and 164 Bcf of natural gas supply in 2022 and 2021, respectively. Our natural gas supply portfolio consists of contracts with varying terms from a diverse group of suppliers. We award these contracts through competitive-bidding processes to ensure reliable and competitively priced natural gas supply. We acquire our natural gas supply from natural gas processors, marketers and producers.

An objective of our supply-sourcing strategy is to provide value to our customers through reliable, competitively priced and flexible natural gas supply and transportation from multiple production areas and suppliers. This strategy is designed to mitigate the impact on our supply from physical interruptions, financial difficulties of a single supplier, natural disasters and other unforeseen force majeure events, as well as to ensure that adequate supply is available to meet the variations of customer demand.

We do not anticipate problems with securing natural gas supply to satisfy customer demand; however, if supply shortages were to occur, we have curtailment provisions in our tariffs that allow us to reduce or discontinue natural gas service to large industrial users and to request that residential and commercial customers reduce their natural gas requirements to an amount essential for public health and safety. In addition, during times of critical supply disruptions, curtailments of deliveries to customers with firm contracts may be made in accordance with guidelines established by appropriate federal, state and local regulatory agencies.

Natural gas supply requirements for our sales customers are impacted by weather and economic conditions. Our customers' usage may also change in response to a variety of factors, including:

- the occurrence of a significant disruption in natural gas supplies, either by itself, or accompanied by higher or lower natural gas prices;
- the availability of more energy-efficient construction methods or home improvements such as installation or replacement of insulated doors and windows, additional or energy efficient insulation and installation or replacement of existing appliances with more efficient appliances; and
- fuel switching from natural gas to other energy alternatives.

In each jurisdiction in which we operate, changes in customer usage are considered in the periodic redesign of our rates.

As of December 31, 2022, we had 57.6 Bcf of natural gas storage capacity under contract with remaining terms ranging from one to ten years and maximum allowable daily withdrawal capacity of approximately 1.7 Bcf. This storage capacity allows us to purchase natural gas during the off-peak season and store it for use in the winter periods. This storage is also needed to support the reliability of gas deliveries during peak demands for natural gas. Approximately 33 percent of our winter natural gas supply needs for our sales customers is expected to be supplied from storage.

In managing our natural gas supply portfolios, we partially mitigate price volatility for our customers using a combination of financial derivatives and natural gas in storage. We have natural gas financial hedging programs that have been authorized by the OCC, KCC and certain jurisdictions in Texas. We do not utilize financial derivatives for speculative purposes, nor do we have trading operations associated with our business.

Demand - See discussions below under Seasonality, Competition and CNG for factors affecting demand for our services.

Seasonality - Natural gas sales to residential and commercial customers are seasonal, as a substantial portion of their natural gas requirements are for heating. Accordingly, the volume of natural gas sales is normally higher during the months of November through March than in other months of the year. The impact on our natural gas sales resulting from weather temperatures that are above or below normal is offset partially through our WNA mechanisms. See the tables above under Regulatory Overview for additional information.

Competition - We encounter competition based on customers' preference for natural gas, compared with other energy alternatives and their comparative prices. We compete primarily to supply energy for space and water heating, cooking and clothes drying. Significant energy usage competition occurs between natural gas and electricity in the residential and small commercial markets. Customers and builders typically make the decision on the type of equipment, and therefore the energy source, at initial installation, generally locking in the chosen energy source for the life of the equipment. Changes in the competitive position of natural gas relative to electricity and other energy alternatives have the potential to cause a decline in consumption of natural gas or in the number of natural gas customers.

We are subject to competition from other pipelines for our large industrial and commercial customers. Under our transportation tariffs, qualifying industrial and commercial customers are able to purchase their natural gas supply from the provider of their choice and contract with us to transport it for a fee. A portion of the transportation services that we provide are at negotiated rates that are below the maximum approved transportation tariff rates. Reduced-rate transportation service may be negotiated when a competitive pipeline is in close proximity or another viable energy option is available to the customer.

CNG - In meeting demand for CNG for motor vehicle transportation, particularly from fleet operators who value its lower greenhouse gas emissions and operating fuel costs relative to gasoline- or diesel-powered vehicles, we supply natural gas to CNG fueling stations. We deploy capital to connect our system to CNG stations built and operated by third parties. As of December 31, 2022, we supply 147 fueling stations, 36 of which we operate in conjunction with our own fleets. Of the 111 remaining stations, 66 are retail and 45 are private stations. We transported approximately 2.8 million Dth to CNG stations each year in 2022 and 2021.

Alternative Fuels – RNG and hydrogen technologies offer potential opportunities to secure new gas supply sources that could be transported through our pipelines. Our evaluation of these technologies and opportunities includes: (1) establishing interconnection guidelines for delivery of alternative fuels to our system, (2) working directly with developers and end-use customers to identify potential alternative fuel supply projects, (3) analyzing pipeline system integrity and gas supply implications, including sourcing opportunities, related to hydrogen use in our system, (4) partnering with industry groups to identify opportunities for hydrogen blending and utilization, and (5) evaluating the opportunity to reduce greenhouse gas emissions through the use of alternative fuels.

ENVIRONMENTAL AND SAFETY MATTERS

See Note 17 of the Notes to Consolidated Financial Statements and Management's Discussion and Analysis of Financial Condition and Results of Operations in this Annual Report for information regarding environmental and safety matters.

HUMAN CAPITAL

We intentionally foster an inclusive work culture, where all viewpoints are welcome, to develop an engaged and high-performing workforce and an environment where top talent wants to work.

Employment - We employed approximately 3,800 people at February 1, 2023, including approximately 700 people at Kansas Gas Service who are subject to collective bargaining agreements. The following table sets forth our contracts with collective bargaining units at February 1, 2023:

Union	Approximate Employees	Contract Expires
The United Steelworkers	400	May 31, 2025
International Brotherhood of Electrical Workers	300	June 30, 2024

We recognize that employees are a key stakeholder group for the success of our business. Therefore, we perform an annual survey to monitor and assess employee engagement.

Workplace Health and Safety - Safety is our number one core value. We are committed to pursuing a zero-incident safety culture, which can reduce risk, enhance productivity and build a strong reputation in the communities in which we operate. Our success is reliant on training and development, performance management and shared responsibility that focuses on engagement and ensures our employees know what is expected to keep themselves, their co-workers, our customers and communities safe. To reinforce our commitment to the safety and well-being of our co-workers, customers and communities, our short-term incentive compensation program includes four operational measures, TRIR, DART, PVIR and ERT. These measures focus on the importance of personal injury prevention, reducing the severity of injuries, safe driving, and public safety. The following table sets forth our performance for the periods indicated:

	Years Ended December 31,		
Operational measure	**2022**	**2021**	**2020**
TRIR	**1.37**	0.96	1.02
DART	**0.22**	0.22	0.28
PVIR	**1.84**	2.10	1.76
ERT	**62.7%**	62.7%	64.5%

TRIR, DART and PVIR are personal safety metrics tracked by the American Gas Association. We regularly rank in the top quartile for similar-sized LDCs for these metrics.

As part of our culture of safety, we continue to closely monitor the COVID-19 pandemic and have maintained many of the precautions put in place in 2020 to allow us to continue to provide safe, reliable service while protecting our co-workers, customers, and communities.

We also are committed to a supportive culture of physical, financial, emotional and social wellness for employees. We provide health and wellness programs to support and inspire our employees to make healthy personal and professional lifestyle choices.

Inclusion and Diversity - Our core values include inclusion and diversity, and we believe in equity and the value and voice of every employee. As part of our commitment, we have and continue to consider inclusion and diversity implications in our recruiting process, Company training, and Company performance monitoring. For example, we monitor our workforce diversity statistics across roles and seniority levels. Additionally, we make available conscious inclusion training to all employees.

We have an Inclusion and Diversity Council, which is chaired by our Chief Executive Officer, and includes five employees serving as permanent members, and 16 employees serving as rotating members with three-year terms. The Inclusion and Diversity Council provides governance and guidance for implementing our strategy and sharing our vision of an inclusive and diverse workforce. In addition, we have employee-led resource groups to provide community and support to our employees based on shared characteristics, interests or experiences.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

All executive officers are elected annually by our Board of Directors and each serves until such person resigns, is removed or is otherwise disqualified to serve or until such officer's successor is duly elected. Our executive officers listed below include the officers who have been designated by our Board of Directors as our Section 16 officers.

Name	Age*		Business Experience in Past Five Years
Robert S. McAnnally	59	2021 to present	President, Chief Executive Officer and Director
		2020 to 2021	Senior Vice President and Chief Operating Officer
		2015 to 2020	Senior Vice President, Operations
Caron A. Lawhorn	61	2019 to present	Senior Vice President and Chief Financial Officer
		2014 to 2019	Senior Vice President, Commercial
Joseph L. McCormick	63	2014 to present	Senior Vice President, General Counsel and Assistant Secretary
Curtis L. Dinan	55	2021 to present	Senior Vice President and Chief Operating Officer
		2020 to 2021	Senior Vice President and Chief Commercial Officer
		2019 to 2020	Senior Vice President, Commercial
		2018 to 2019	Senior Vice President and Chief Financial Officer
		2014 to 2018	Senior Vice President, Chief Financial Officer and Treasurer
Mark A. Bender	58	2015 to present	Senior Vice President, Administration and Chief Information Officer
W. Kent Shortridge	56	2022 to present	Senior Vice President, Operations and Customer Service
		2018 to 2022	Managing Vice President, Operations
		2014 to 2018	Vice President, Operations - Oklahoma Natural Gas
Brian F. Brumfield	55	2022 to present	Vice President, Chief Accounting Officer and Controller
		2017 to 2022	Controller, Tucson Electric Power/UNS Energy

* As of January 1, 2023

No family relationship exists between any of the executive officers, nor is there any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

AVAILABLE INFORMATION

We make available, free of charge, on our website (www.onegas.com) our Annual Reports, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, amendments to those reports filed or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Exchange Act and reports of holdings of our securities filed by our officers and directors under Section 16 of the Exchange Act. Such materials are available as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC, which also makes these materials available on its website (www.sec.gov). Our Code of Business Conduct and Ethics, Corporate Governance Guidelines, Certificate of Incorporation, bylaws, the written charters of our Audit Committee, Executive Compensation Committee, Corporate Governance Committee and Executive Committee and our ESG Report are also available on our website, and copies of these documents are available upon request.

In addition to filings with the SEC and materials posted on our website, we also use social media platforms as channels of information distribution to reach investors and other stakeholders. Information contained on our website and posted on or disseminated through our social media accounts is not incorporated by reference into this report.

ITEM 1A. RISK FACTORS

Our investors should consider the following risks that could affect us and our business. Although we believe we have discussed the key factors, our investors need to be aware that other risks may prove to be important in the future. New risks may emerge at any time, and we cannot predict such risks or estimate the extent to which they may affect our financial performance. Investors should carefully consider the following discussion of risks and the other information included or incorporated by reference in this Annual Report, including Forward-Looking Statements, which are included in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.

OPERATIONAL RISKS

Our business is subject to operational hazards and unforeseen interruptions that could materially and adversely affect our business and for which we may not be insured adequately.

We are subject to all the risks and hazards typically associated with the natural gas distribution business that could affect the public safety and reliability of our distribution system. Operating risks include, but are not limited to, leaks, accidents, pipeline ruptures and the breakdown or failure of equipment or processes. Other operational hazards and unforeseen interruptions include adverse weather conditions, accidents, explosions, fires, the collision of equipment or vehicles with our pipeline facilities and catastrophic events, such as severe weather events, hurricanes, thunderstorms, tornadoes, sustained extreme temperatures, earthquakes, floods, acts of terrorism, pandemics and other health crises, or other similar events beyond our control. Climate change could cause these catastrophic events to become more severe or more frequent. It is also possible that our facilities, or those of our counterparties or service providers, could be direct targets or indirect casualties of an act of terrorism, including cyber-attacks. These issues could result in legal liability, repair and remediation costs, increased operating costs, significant increased capital expenditures, regulatory fines and penalties and other costs and a loss of customer confidence.

Our general liability, cyber, and property insurance policies for many of these hazards and risks are subject to certain limits, deductibles, and policy exclusions. The insurance proceeds received for any loss of, or any damage to, any of our systems or facilities or to third parties may not be sufficient to restore the total loss or damage. Further, the proceeds of any such insurance may not be received in a timely manner. The occurrence of any of the foregoing could have a material adverse effect on our financial condition, results of operations and cash flows.

We may be unable to attract and retain management and professional and technical employees, or experience workforce disruptions due to strikes or work stoppages by our unionized employees, which could adversely impact our operations, earnings, and cash flows.

Our ability to implement our business strategy, satisfy our regulatory requirements, and serve our customers is dependent upon our ability to continue to recruit and employ a skilled, agile, diverse, and engaged workforce consisting of talented and experienced managers, professional and technical employees. The competition for talent has become increasingly intense and we may experience increased employee turnover due to a tightening labor market. If we are unable to recruit and retain an appropriately qualified workforce, we could encounter operating challenges primarily due to a loss of institutional knowledge and expertise, errors due to inexperience, or the lengthy time period typically required to adequately train replacement personnel. In addition, higher costs could result from loss of productivity, increased safety compliance issues, or cost of contract labor. Additionally, approximately 19 percent of our employees are represented by collective-bargaining units under collective-bargaining agreements. Disputes over the agreements or failure to timely and effectively renegotiate new agreements upon their expiration could have a negative effect on our business, financial condition and results of operations or result in a work stoppage. Any future work stoppage could, depending on the breadth and the length of the work stoppage, have a material adverse effect on our financial condition, results of operations and cash flows.

The availability of adequate natural gas pipeline transportation and storage capacity and natural gas supply may decrease and impair our ability to meet customers' natural gas requirements and our financial condition may be adversely affected.

In order to meet customers' natural gas demands, we rely on and must obtain sufficient natural gas supplies, pipeline transportation and storage capacity from third parties. If we are unable to obtain these, our ability to meet our customers' natural gas requirements could be impaired. If a substantial disruption to or reduction in natural gas supply, pipeline capacity or storage capacity occurred due to operational failures or disruptions, legislative or regulatory actions, hurricanes, tornadoes, floods, earthquakes, extreme cold weather, acts of terrorism, or cyber-attacks or acts of war, our operations or financial results could be adversely affected.

Our business increasingly relies on technology, the failure of which may adversely affect our financial results and cash flows.

Due to increased technology advances, we have become more reliant on technology to effectively operate our business. We use computer programs and applications to help run our business, including an enterprise resource planning system that integrates data and reporting activities across our Company. Additionally, certain portions of our IT systems and infrastructure are provided or maintained by third-party vendors. The failure of these or other similarly important technologies, the lack of alternative technologies, or our inability to have these technologies supported, updated, expanded, or integrated into other technologies, could hinder our operations, and adversely impact our financial condition and results of operations.

The occurrence of cyber breaches or physical security attacks on our business, or those of third parties, may disrupt or adversely affect our operations or result in the loss or misuse of confidential and proprietary information.

Any cyber breaches or physical security attacks, or threats of such attacks, that affect our IT systems, distribution facilities, customers, suppliers and third-party service providers or any financial data could disrupt normal business operations, expose sensitive information, and/or lead to physical damages that may have a material adverse effect on our business. A severe attack or security breach could adversely affect our business reputation, diminish customer confidence, disrupt operations, subject us to financial liability or increased regulation, increase our costs and expose us to material legal claims and liability which may not be fully covered by insurance, and our business, financial condition, results of operations and cash flows could be adversely affected. As cyber or physical security attacks become more frequent and sophisticated, we could be required to incur increased costs to strengthen our systems or to obtain additional insurance coverage against potential losses. Federal and state regulatory agencies, such as DHS and TSA, are increasingly focused on risks related to physical security and cybersecurity in general and have promulgated more stringent security regulations specifically for certain federal contractors and critical infrastructure sectors, including natural gas distribution. Any failure to comply with such government regulations may have a material adverse effect on our results of operations and financial condition.

We are subject to various risks associated with climate change which could increase our operating costs or restrict our opportunities in new or existing markets, adversely affecting our financial results, growth, cash flows and results of operations.

Climate change may increase the likelihood of extreme weather in our service territory, and our customers' energy use could increase or decrease depending on the duration and magnitude of any changes. A decrease in energy use due to weather changes may affect our financial condition through decreased revenues and cash flows which are not adequately offset by our WNA mechanisms. Extreme weather conditions in general require increased system resiliency, adding to costs, and can contribute to increased system stresses, including service interruptions. Weather conditions outside of our operating territory could also have an impact on our revenues and cash flows by affecting natural gas prices and the availability of our leased transportation and storage capacity. Weather impacts our operations primarily through severe weather events, including hurricanes, thunderstorms, tornadoes, sustained extreme temperatures, snow and ice storms, earthquakes, floods, or other similar events beyond our control. To the extent the frequency of extreme weather events increases, our costs of providing service and our working capital requirements could increase.

REGULATORY AND LEGISLATIVE RISKS

We are subject to federal, state, and local regulation of the safety of our systems and operations, including pipeline safety, system integrity, and the safety of our employees and facilities that may require significant expenditures or, in the case of noncompliance, substantial fines or penalties.

We are subject to regulation under federal pipeline safety statutes promulgated by PHMSA, DOT, OSHA, and any analogous state regulations. These include safety requirements for the design, construction, operation, and maintenance of pipelines, including transmission and distribution pipelines. Additionally, the workplaces associated with our facilities are subject to the requirements of DOT and OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. Compliance with existing or new laws and regulations may result in increased capital, operating and other costs which may not be recoverable in rates from our customers or may impact materially our competitive position relative to other energy providers. The failure to comply with these laws, regulations and other requirements, or an accident or injury to employees could expose us to civil or criminal liability, enforcement actions, fines, penalties, or injunctive measures that may not be recoverable through our rates and could have a material adverse effect on our business, financial condition, results of operations, cash flows, and reputation.

We are subject to federal, state, and local laws, rules and regulations that could impact our ability to earn a reasonable rate of return on our invested capital and to fully recover our invested capital, operating costs, and natural gas costs.

We are subject to regulatory oversight from various federal, state, and local regulatory authorities, including the OCC, KCC, RRC and various municipalities in Texas. Regulatory actions from these authorities relate to allowed rates of return, rate design and construct, and purchased gas and operating cost recovery. Therefore, our returns are continuously monitored and are subject to challenge for their reasonableness by regulatory authorities or third-party intervenors. Our ability to obtain timely future rate increases depends on regulatory discretion and therefore, there can be no assurance that we will be able to obtain rate increases, fully recover our costs or that our authorized rates of return will continue at the current levels, which could adversely impact our results of operations, financial condition, and cash flows.

In the normal course of business, assets are placed in service before regulatory action is taken, such as filing a rate case or seeking interim recovery under a capital tracking mechanism that could result in an adjustment of our returns. Once we make a regulatory filing, regulatory bodies have the authority to suspend implementation of the new rates while evaluating the filing. Because of this process, we may suffer the negative financial effects of having placed assets in service that do not initially earn our authorized rate of return or may not be allowed recovery on such expenditures at all.

We are subject to environmental regulations and legislation, including those intended to address climate change, which could increase our operating costs, adversely affecting our financial results, growth, cash flows and results of operations.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities, including the EPA and any analogous state agencies, relating to protection of the environment, including those that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, the clean-up of contaminated sites, groundwater quality and availability, plant and wildlife protection, as well as work practices related to employee health and safety. Environmental legislation also requires that our facilities, sites, and other properties associated with our operations be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. The failure to comply with any laws, regulations, permits and other requirements, or the discovery of presently unknown environmental conditions, could expose us to civil or criminal liability, enforcement actions and regulatory fines and penalties and could have a material adverse effect on our business, financial condition, results of operations and cash flows.

International, federal, regional and/or state legislative and/or regulatory initiatives may attempt to regulate greenhouse gas emissions, including carbon dioxide and methane, as a response to the threat of climate change. Various states and municipalities have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on areas such as greenhouse gas cap and trade programs, carbon taxes, reporting and tracking programs, and restrictions on emissions. Such laws or regulations could impose costs tied to carbon emissions, operational requirements or restrictions, or additional charges to fund energy efficiency activities. They could also incentivize alternative energy sources, impose costs or restrictions on end users of natural gas, or result in other costs or requirements, such as costs associated with the adoption of new infrastructure and technology to respond to new mandates.

We are subject to federal, state, and local laws, rules and regulations that could affect our operations and financial results.

Our business and operations are subject to regulation by a number of federal agencies, including FERC, CFTC, IRS and various state agencies in Oklahoma, Kansas, and Texas, and we are subject to numerous other federal and state laws and regulations. Future changes to laws, regulations and policies may impair our ability to compete for business or recover costs and could adversely affect our cash flows, restrict our ability to make capital investments and may cause us to increase debt and take other actions to conserve cash. Any compliance failure related to these laws and regulations may result in fines, penalties or injunctive measures affecting our operating assets. The fines or penalties for noncompliance with laws and regulations may not be recoverable through our rates. Our failure to comply with applicable regulations could result in a material adverse effect on our business, financial condition, results of operations and cash flows.

FINANCIAL, ECONOMIC AND MARKET RISKS

Unfavorable economic and market conditions could adversely affect our financial condition, earnings, cash flows and limit our future growth.

Weakening economic activity in our markets and supply chain disruptions could result in a loss of existing customers, fewer new customers, especially in newly constructed homes and other buildings, or a decline in energy consumption, any of which could adversely affect our revenues or restrict our future growth. These conditions may make it more difficult for customers to pay their natural gas bills, leading to slow collections and higher-than-normal levels of accounts receivable, which in turn could increase our financing requirements and bad debt expense. Customers may also experience difficulties paying their natural gas bills in the instance of severe weather events that result in higher usage and higher natural gas prices, reducing our collections and increasing our financing requirements and bad debt expense, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity, and prospects.

Changes in supply and demand within the natural gas markets, as well as other factors, could cause an increase in the price of natural gas. Market conditions can also lead to short-term price spikes in natural gas prices, such as high demand during periods of extreme cold weather or system constraints at specific delivery locations. An increase in the price of natural gas could cause us to experience a significant increase in short-term or long-term debt because we must pay suppliers for natural gas when purchased.

We cannot predict the timing, severity, or duration of any future economic slowdowns or natural gas market disruptions. Fluctuations and uncertainties in the economy may result in higher interest rates and inflationary pressures on the costs of goods, services, and labor. This could increase our expenses and capital spending and decrease our cash flows if we are not able to recover or recover timely such increased costs from our customers. The foregoing could adversely affect our business, financial condition, results of operations and cash flows.

Our business activities are concentrated in three states.

We provide natural gas distribution services to customers in Oklahoma, Kansas, and Texas. Changes in the regional economies, politics, regulations, regulatory decisions by state and local regulatory authorities, and weather patterns of these states could adversely impact our financial condition, results of operations and cash flows.

The inability to access capital or significant increases in the cost of capital could adversely affect our results of operations, cash flows and financial condition.

Our ability to obtain adequate and cost-effective financing is dependent upon the liquidity of the financial markets, as well as our financial condition and credit ratings. Our long-term debt is currently rated as “investment grade” by both of our rating agencies. We rely upon access to both the short-term and long-term credit and capital markets to satisfy our liquidity requirements. If adverse credit conditions or a downgrade in our ratings outlook were to cause a significant limitation on our access to the private credit and public capital markets, we could see a reduction in our liquidity. A significant reduction in our liquidity could in turn trigger a negative change in our ratings outlook or a reduction in our credit ratings by one or both of our rating agencies. Such a downgrade could further limit our access to private credit and/or public capital markets and increase our costs of borrowing. Additionally, the inability to access adequate capital or an increase in the cost of capital may require us to conserve cash, prevent or delay us from making capital expenditures, and require us to reduce or eliminate our dividend or other discretionary uses of cash.

Our financing arrangements subject us to various restrictions that could limit our operating flexibility, earnings, and cash flows.

The indentures governing our Senior Notes and our ONE Gas Credit Agreement contain customary covenants that restrict our ability to create or permit certain liens, to consolidate or merge, or to convey, transfer or lease substantially all of our properties and assets. Events beyond our control could impair our ability to satisfy these requirements. As long as our indebtedness remains outstanding, these restrictive covenants could impair our ability to expand or pursue our growth strategy.

In addition, the breach of any covenants or any payment obligations in any of these debt agreements will result in an event of default under the applicable debt instrument. If an event of default were to occur, the holders of the defaulted debt may have the ability to cause all amounts outstanding with respect to that debt to be due and payable, subject to applicable grace periods. This could trigger cross-defaults under our other debt agreements, including our Senior Notes. Forced repayment of some or all of our indebtedness could require us to incur new debt at a higher cost, which would have an adverse impact on our financial condition, results of operations and cash flows.

We may pursue acquisitions, divestitures, and other strategic opportunities which, if not successful, may adversely impact our results of operations, cash flows and financial condition.

As part of our strategic objectives, we may pursue acquisitions to complement or expand our business, as well as divestitures and other strategic opportunities. We may not be able to successfully negotiate, finance or receive regulatory approval for future acquisitions or integrate the acquired businesses with our existing business and services. These efforts may also distract our management and employees from day-to-day operations and require substantial commitments of time and resources. Future acquisitions could result in potentially dilutive issuances of equity securities, a decrease in our liquidity as a result of our using a significant portion of our available cash or borrowing capacity to finance the acquisition, the incurrence of debt, contingent liabilities and amortization expenses and substantial goodwill. The effects of these strategic decisions may have long-term implications that are not likely to be known to us in the short-term. We may be materially and adversely affected if we are unable to successfully integrate businesses that we acquire.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The following table sets forth the approximate miles of distribution mains and transmission pipelines we own as of December 31, 2022:

Properties (miles)	OK	KS	TX	Total
Distribution	19,400	11,700	11,000	42,100
Transmission	600	1,500	300	2,400
Total properties	20,000	13,200	11,300	44,500

We lease approximately 300 thousand square feet of office space and other facilities for our operations. In addition, we have 57.6 Bcf of natural gas storage capacity under contract, with maximum allowable daily withdrawal capacity of approximately 1.7 Bcf.

ITEM 3. LEGAL PROCEEDINGS

See Note 17 of the Notes to Consolidated Financial Statements in this Annual Report for information regarding legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II.

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

MARKET HOLDERS AND DIVIDENDS

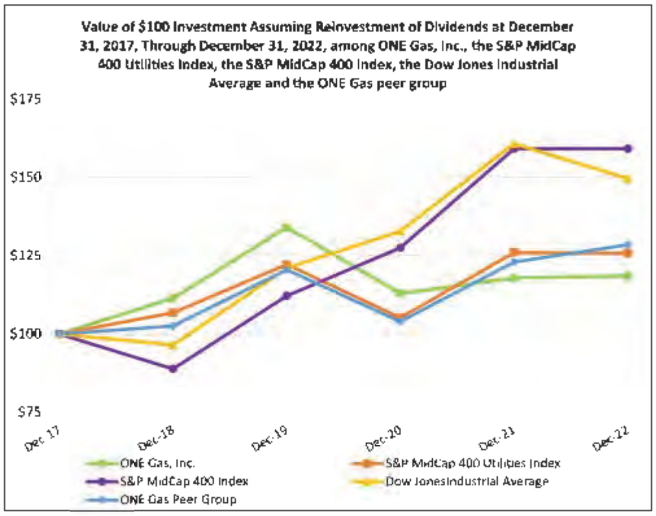
Our common stock is listed on the NYSE under the trading symbol "OGS."

At February 17, 2023, there were 9,437 registered shareholders of our common stock.

In January 2023, we declared a dividend of $0.65 per share ($2.60 per share on an annualized basis) for shareholders of record on February 24, 2023, payable on March 10, 2023.

Performance Graph

The following performance graph compares the performance of our common stock with the S&P MidCap 400 Utilities Index, the S&P MidCap 400 Index, the Dow Jones Industrial Average and a ONE Gas peer group during the period beginning December 31, 2017 and ending on December 31, 2022. This graph assumes a $100 investment in our common stock and in each of the indices at the beginning of the period and a reinvestment of dividends paid on such investments throughout the period.



	Cumulative Total Return As of Each Year Ended December 31,				
	2018	2019	2020	2021	2022
ONE Gas, Inc.	$ 111.40	$ 133.99	$ 112.91	$ 117.83	$ 118.53
S&P MidCap 400 Utilities Index	$ 106.81	$ 122.12	$ 105.18	$ 125.96	$ 125.76
S&P MidCap 400 Index	$ 88.90	$ 112.17	$ 127.48	$ 159.01	$ 159.01
Dow Jones Industrial Average	$ 96.52	$ 120.98	$ 132.75	$ 160.55	$ 149.53
ONE Gas Peer Group*	$ 104.14	$ 123.50	$ 109.50	$ 128.69	$ 133.82

* The ONE Gas peer group used in this graph is the same peer group that will be used in determining our level of performance under our 2022 performance units at the end of the three-year performance period and is comprised of the following companies: Alliant Energy Corporation; Atmos Energy Corporation; Avista Corporation; CenterPoint Energy, Inc.; Chesapeake Utilities Corporation; CMS Energy Corporation; New Jersey Resources Corporation; NiSource Inc.; Northwest Natural Holding Company; NorthWestern Corporation; South Jersey Industries, Inc.; Southwest Gas Holdings, Inc.; and Spire Inc.

ITEM 6. [RESERVED]

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our audited consolidated financial statements and Notes to Consolidated Financial Statements in this Annual Report.

EXECUTIVE SUMMARY

We are a 100-percent regulated natural gas distribution company. As such, our regulators determine the rates we are allowed to charge for our service based on the revenue requirements needed to achieve our authorized rates of return. We earn revenues from the delivery of natural gas, but do not earn a profit on the natural gas that we deliver, as those costs are passed through to our customers at cost. The primary components of our revenue requirements are the amount of capital invested in our business, which is also known as rate base, our allowed rate of return on our capital investments and our recoverable operating expenses, including depreciation, interest expense and income taxes. The variable component of our rates is dependent on the consumption of natural gas, which is impacted primarily by the weather and, to a lesser extent, economic activity. While we have WNA mechanisms that adjust sales customers' bills when actual HDDs differ from normalized HDDs, these mechanisms are in place for only a portion of the year, except in Kansas, and do not offset all fluctuations in usage resulting from weather variability. Accordingly, the weather can have either a positive or negative impact on our financial performance.

Our financial performance, therefore, is contingent on a number of factors, including: (1) our regulatory construct, including the rates we are allowed to charge for our service, and the authorized rates of return on our investments in rate base; (2) the consumption of natural gas, which impacts the amount of natural gas sales derived from the variable component of our rates; (3) customer growth; (4) our operating performance; and (5) the perceived value of natural gas relative to other energy sources, particularly electricity, which influences our customers' choice of natural gas to provide a portion of their energy needs.

We are subject to regulatory requirements for pipeline integrity, pipeline and cyber security and environmental compliance. These requirements impact our operating expenses and the level of capital expenditures required for compliance. Historically, our regulators have allowed recovery of these expenditures. However, because integrity and environmental regulations are frequently changing, our capital and operating expenditures to comply are changing as well. Although we believe our regulators will continue to allow recovery of such expenditures in the future, we will continue to make these expenditures with no assurance about if, or over what period, we will be permitted to recover them.

RECENT DEVELOPMENTS

<u>Long-term Debt and Securitization Transactions</u> - On August 8, 2022, we issued $300 million of 4.25 percent senior notes due September 2032. The proceeds from the issuance were used to repay amounts outstanding under our commercial paper program and for general corporate purposes.

In August 2022, Oklahoma Natural Gas received proceeds of approximately $1.3 billion, which represents the amount of the securitization bonds issued by the ODFA, less issuance costs. The receipt of these proceeds represents Oklahoma Natural Gas' recovery of approximately $1.3 billion of authorized extraordinary natural gas purchase costs and other operational costs incurred during Winter Storm Uri, as well as carrying costs.

In August 2022, we called $750 million of the $1.0 billion of 0.85 percent senior notes due March 2023, $150 million of the $700 million of 1.10 percent senior notes due March 2024 and the remaining $400 million of outstanding floating-rate senior notes due March 2023, using the proceeds received from the securitization transaction for Oklahoma Natural Gas.

In November 2022, KGSS-I issued $336 million of 5.486 percent Securitized Utility Tariff Bonds. KGSS-I used the proceeds from the issuance to purchase the Securitized Utility Tariff Property from Kansas Gas Service, pay for debt issuance costs, and reimburse Kansas Gas Service for upfront securitization costs paid by Kansas Gas Service on behalf of KGSS-I.

In November 2022, we called the remaining $250 million of the $1.0 billion of 0.85 percent senior notes due March 2023 and $77 million of the $700 million of 1.10 percent senior notes due March 2024, using the proceeds from the securitization transaction for Kansas Gas Service.

See “Regulatory Activities,” “Liquidity and Capital Resources,” and Notes 1 and 10 of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of the securitization transactions.

At-the-Market Equity Program - For the year ended December 31, 2022, we sold and issued 403,792 shares of our common stock for $35.0 million, generating proceeds, net of issuance costs, of $34.7 million. Additionally, for the year ended December 31, 2022, we executed forward sale agreements for 1,451,474 shares of our common stock. On December 30, 2022, we settled forward sales agreements with respect to 1,162,071 shares of our common stock for net proceeds of $93.8 million. Had we settled the remaining 289,403 shares under the outstanding forward sale agreements as of December 31, 2022, we would have generated net proceeds of approximately $21.7 million.

See “Liquidity and Capital Resources” and Note 6 of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of our at-the-market equity program.

ONE Gas Credit Agreement - On March 16, 2022, we entered into the first amendment to the second amended and restated ONE Gas Credit Agreement, which was previously amended and restated on March 16, 2021. The amendment extends the maturity date of the ONE Gas Credit Agreement to March 16, 2027, from March 16, 2026, and amends the ONE Gas Credit Agreement to provide that we may extend the maturity date, subject to the lenders’ consent, by one year two additional times. The amendment also changes the benchmark rate defined in the ONE Gas Credit Agreement to SOFR. All other material terms and conditions of the ONE Gas Credit Agreement remain in full force and effect.

Dividend - In January 2023, we declared a dividend of $0.65 per share ($2.60 per share on an annualized basis) for shareholders of record on February 24, 2023, payable on March 10, 2023.

REGULATORY ACTIVITIES

Oklahoma - In April 2021, Oklahoma Natural Gas submitted an initial application requesting a financing order pursuant to the securitization legislation in Oklahoma. In January 2022, the OCC approved a financing order that reflected the terms of a settlement agreement reached in November 2021, which included an agreement that all extreme gas purchase and extraordinary costs incurred as a result of Winter Storm Uri were reasonable and prudent and a financing order should be issued to recover these costs through securitization. In May 2022, pursuant to the securitization statute in Oklahoma, the Oklahoma Supreme Court validated that the bond issuance proposed by the ODFA complied with the securitization statute and the laws of Oklahoma.

In August 2022, the ODFA completed the issuance of $1.35 billion in ratepayer-backed bonds with varying scheduled final maturities over 30 years, consistent with the OCC financing order. The bonds are limited and special revenue obligations of the ODFA, payable solely from the securitization bond collateral and are not an obligation of Oklahoma Natural Gas or any of its affiliates.

The proceeds received by Oklahoma Natural Gas were approximately $1.3 billion, which represents the amount of the securitization bonds issued by the ODFA less issuance costs. The receipt of these proceeds represents Oklahoma Natural Gas’ recovery of the approximately $1.3 billion of authorized extraordinary natural gas purchase costs and other operational costs incurred during Winter Storm Uri, as well as carrying costs. Beginning September 1, 2022, Oklahoma Natural Gas acts as a servicer, with responsibility for collecting the securitization charges from Oklahoma customers that are then submitted to the ODFA to repay the securitization bonds.

As required, PBRC filings are made annually on or before March 15, until the next general rate case which is required to be filed on or before June 30, 2027. In March 2022, Oklahoma Natural Gas filed its required PBRC application for a calendar year 2021 test year. The filed request included a $19.7 million base rate revenue increase, $2.3 million energy efficiency incentive, and $9.1 million of estimated EDIT to be credited to customers in 2023. In May 2022, the Public Utility Division (“PUD”) of the OCC filed responsive testimony supporting an increase of $19.6 million and the Office of the Attorney General filed a statement of position supporting PUD’s position. Pursuant to its tariff, Oklahoma Natural Gas placed new rates into effect on July 13, 2022, reflecting a base rate revenue increase of $19.6 million. These rates were subject to refund until approved by the OCC. In August 2022, a stipulation was filed reflecting the $19.6 million increase supported by PUD and unopposed by the office of the Attorney General. In September 2022, a hearing was held and the administrative law judge recommended approval of the joint stipulation. In November 2022, the OCC issued an order approving the joint stipulation.

As required by OCC rule, in April 2022, Oklahoma Natural Gas filed a request for approval of a demand portfolio of conservation and energy efficiency programs for calendar years 2023-2025. The request included an annual portfolio of program costs of $17.4 million, with an estimated annual utility incentive of $2.6 million. In September 2022, a joint stipulation and settlement agreement was entered into with the PUD supporting Oklahoma Natural Gas' request. A hearing was held in October 2022, and the administrative law judge recommended approval of the joint stipulation and settlement agreement. In December 2022, the OCC issued an order approving the joint stipulation.

In May 2021, Oklahoma Natural Gas filed a general rate case. In October 2021, a joint stipulation and settlement agreement was signed by all parties to the rate case. In November 2021, the OCC issued an order approving the joint stipulation and settlement agreement. Upon approval of the order, Oklahoma Natural Gas' base rates increased by $15.3 million. Premised on an ROE of 9.4 percent and a common equity ratio of 58.55 percent, the order also includes the continuation of the PBRC tariff that was established in 2009. The approved order allows Oklahoma Natural Gas to recover commodity costs of no more than $5.0 million annually for the purchase of RNG and requires Oklahoma Natural Gas to file an application on or before December 31, 2022, requesting approval of an RNG pilot program including an "opt-in" tariff allowing Oklahoma Natural Gas to allocate costs and benefits of RNG to those customers who choose RNG for their fuel source.

In December 2022, Oklahoma Natural Gas filed the required request for an RNG Pilot Program and Voluntary Tariff pursuant to the requirement in the rate case order. The proposed tariff will allow all residential, small commercial and industrial sales customers to voluntarily purchase the environmental attributes of RNG up to the equivalent of 10 Dth per month. If approved, the tariff will be in effect through 2027. Assessment of the tariff and pilot program will be made in the rate case required to be filed on or before June 30, 2027. An order is expected no earlier than the third quarter of 2023.

In May 2021, a bill amending the Oklahoma state income tax code was signed into law that reduced the state income tax rate to four percent from six percent beginning January 1, 2022. As a result of the enactment of this legislation, we remeasured our ADIT. As a regulated entity, the reduction in ADIT of $29.3 million was recorded as a regulatory liability. The impact of the change in the state income tax rate on Oklahoma Natural Gas' rates, as well as the timing and amount of the impact on the annual crediting mechanism for the EDIT regulatory liability, was not material and is included in the March 15, 2022 PBRC filing, as approved in November 2022.

Kansas - In March 2021, the KCC issued an order adopting the KCC staff's recommendation to open company-specific dockets to accept each utility's filing of financial impact compliance reports and permit the KCC staff to conduct a review of the utility's compliance report and its actions during Winter Storm Uri. In April 2021, a bill permitting the utilities to pursue securitization to finance extraordinary expenses, such as fuel costs incurred during extreme weather events, was signed into law by the Kansas governor. The law gives the KCC the authority to oversee and authorize the issuance of ratepayer-backed securitized bonds issued by a public utility.

In May 2021, Kansas Gas Service filed a motion in its company-specific docket opened by the KCC, requesting a limited waiver of the penalty provisions of its tariff to eliminate the multipliers in the penalty calculation when calculating the penalties to assess on marketers and individually-balanced transportation customers for their unauthorized natural gas usage during Winter Storm Uri. In March 2022, the KCC issued an order approving a settlement, which modified the penalty provisions of Kansas Gas Service's tariffs and included a carrying charge of two percent on amounts due to Kansas Gas Service. Amounts collected from these penalties reduce the regulatory asset for the winter weather event, up to $52.6 million. Through December 31, 2022, we have collected $50.5 million of these penalties.

In July 2021, Kansas Gas Service submitted its financial plan to the KCC as required by the company-specific docket opened by the KCC in March 2021. The plan included a proposal for a newly formed, bankruptcy remote subsidiary of the Company to issue securitized utility tariff bonds to recover the extraordinary costs resulting from Winter Storm Uri from Kansas Gas Service's customers. In February 2022, the KCC issued an order approving a unanimous settlement agreement that allows Kansas Gas Service to recover extraordinary costs, net of any penalties recovered from marketers and individually-balanced transportation customers, plus carrying costs, by seeking a financing order from the KCC for the issuance of securitized utility tariff bonds.

In March 2022, Kansas Gas Service submitted its application for a financing order to the KCC as contemplated by the unanimous settlement agreement, requesting approval to issue securitized utility tariff bonds to recover extraordinary costs resulting from Winter Storm Uri. In July 2022, Kansas Gas Service, the KCC Staff and the Citizens' Utility Ratepayer Board reached a settlement agreement for the issuance of a financing order allowing a newly formed, bankruptcy remote subsidiary of the Company to issue securitized utility tariff bonds. In August 2022, the KCC issued an order approving the agreement and also issued a financing order.

As part of the order, we created KGSS-I, a special-purpose, wholly-owned subsidiary of ONE Gas, and filed a registration statement with the SEC, for the purpose of issuing securitized utility tariff bonds. The registration statement was declared effective on November 7, 2022.

In November 2022, KGSS-I issued $336 million of 5.486 percent Securitized Utility Tariff Bonds. KGSS-I used the proceeds from the issuance to purchase the Securitized Utility Tariff Property from Kansas Gas Service, pay for debt issuance costs, and reimburse Kansas Gas Service for upfront securitization costs paid by Kansas Gas Service on behalf of KGSS-I. See Note 4 of the Notes to Consolidated Financial Statements in this Annual Report for additional information about the Securitized Utility Tariff Bonds and Notes 10 and 11 of the Notes to Consolidated Financial Statements in this Annual Report for additional information about the securitization transaction.

In August 2022, Kansas Gas Service submitted an application to the KCC requesting an increase of approximately $7.8 million related to its GSRS. The KCC issued an order in November 2022 authorizing an increase of $7.7 million, and the new surcharge became effective on December 1, 2022.

In August 2022, Kansas Gas Service submitted an application to the KCC requesting certain changes to Section 7 of its General Terms and Conditions tariff. These changes would revise the tariff to use Kansas Gas Service's average embedded cost to determine the cost for service line installations and replacements as well as certain customer requested work. The KCC has 240 days to review the request.

In August 2021, Kansas Gas Service submitted an application to the KCC requesting an increase of approximately $7.6 million related to its GSRS. The KCC issued an order in November 2021, and the new surcharge became effective on December 1, 2021.

In May 2020, a bill amending the Kansas state income tax code was signed into law that exempts public utilities regulated by the KCC from paying Kansas state income taxes beginning January 1, 2021, and authorizes the KCC to adjust utility rates for the elimination of Kansas state income tax beginning January 1, 2021. As a result of the enactment of this legislation, we remeasured our ADIT. As a regulated entity, the reduction in ADIT of $84.2 million was recorded as a regulatory liability and will be refunded to our customers. This adjustment had no material impact on our income tax expense and no impact on our cash flows for the years ended December 31, 2022 and 2021. The bill stipulates that, if requested by the utility, this EDIT will be returned to Kansas customers over a period of no less than 30 years, with the exact timing to be determined in our next general rate proceeding. In August 2020, Kansas Gas Service submitted an application to the KCC to reduce its base rates by approximately $4.9 million to reflect the elimination of Kansas state income taxes. In December 2020, the KCC approved the application, effective January 1, 2021.

Texas - Pursuant to securitization legislation enacted in Texas as a result of Winter Storm Uri and a June 2021 RRC Notice to Gas Utilities, Texas Gas Service submitted an application to the RRC in July 2021, for an order authorizing the amount of extraordinary costs for recovery and other such specifications necessary for the issuance of securitized bonds.

In November 2021, the RRC approved a unanimous settlement agreement between Texas Gas Service, the other natural gas utilities in Texas participating in the securitization process, the staff of the RRC and all intervenors. The settlement agreement provides that all costs incurred by Texas Gas Service to purchase natural gas during Winter Storm Uri were reasonable, necessary and prudently incurred.

In February 2022, the RRC issued a single financing order for Texas Gas Service and other natural gas utilities in Texas participating in the securitization process, which included a determination that the approved costs will be collected from customers over a period of not more than 30 years. The TPFA formed the Texas Natural Gas Securitization Finance Corporation, a new independent public authority, that will issue the securitized bonds, which are expected to be issued by April 2023. At December 31, 2022, Texas Gas Service has deferred approximately $243.1 million in extraordinary costs associated with Winter Storm Uri, which includes $43.8 million attributable to the former West Texas service area. Pursuant to the approved settlement order, in January 2022, Texas Gas Service began collecting the extraordinary costs, including carrying costs, associated with Winter Storm Uri attributable to the former West Texas service area from those customers.

West-North Service Area - In June 2022, Texas Gas Service filed a rate case seeking to consolidate its West Texas, North Texas and Borger/Skellytown service areas into a single West-North service area and requesting a rate increase of $13.0 million. In January 2023, the RRC approved the consolidation and a rate increase of $8.8 million premised on a return on equity of 9.6 percent and a common equity ratio of 59.74 percent equity. The new rates were implemented in February 2023.

West Texas Service Area - In March 2022, Texas Gas Service made GRIP filings for all customers in the former West Texas service area, requesting a $5.0 million increase to be effective in July 2022. In June 2022, the city of El Paso denied the requested increase and assessed fees associated with its review of the filing. Texas Gas Service appealed the city's action to the

RRC. In August 2022, the RRC approved the appealed rates. All other municipalities, and the RRC, approved the new rates or allowed them to take effect with no action. Texas Gas Service implemented the new rates in July 2022.

In March 2021, Texas Gas Service made GRIP filings for all customers in the former West Texas service area, requesting an increase of $9.7 million to be effective in July 2021. In June 2021, the city of El Paso approved a motion which found the GRIP filing to be in compliance with the GRIP statute. The city subsequently denied the requested increase and assessed fees associated with its review of the filing. In July 2021, Texas Gas Service appealed the city's action to the RRC. The RRC granted and approved the appeal, and new rates became effective in August 2021. All other municipalities, and the RRC, approved the new rates or allowed them to take effect with no action.

Central-Gulf Service Area - In February 2023, Texas Gas Service made GRIP filings for all customers in the Central-Gulf service area, requesting an $11.5 million increase to be effective in June 2023.

In February 2022, Texas Gas Service made GRIP filings for all customers in the Central-Gulf service area, requesting a $9.1 million increase to be effective in June 2022. All municipalities, and the RRC, approved the new rates and new rates became effective in June 2022.

In February 2021, Texas Gas Service made GRIP filings for all customers in the Central-Gulf service area, requesting an increase of $10.7 million to be effective in June 2021. All municipalities, and the RRC, approved the new rates or allowed them to take effect with no action.

Other Texas Service Areas - In April 2022, Texas Gas Service made its annual COSA filings for the incorporated area of the Rio Grande Valley service area, requesting an increase of $2.9 million. In July 2022, the municipalities approved an increase of $2.5 million, and new rates became effective in August 2022.

In April 2021, Texas Gas Service made its annual COSA filings for the incorporated areas of the Rio Grande Valley service area and the North Texas service area. In July 2021, the cities in the Rio Grande Valley and North Texas service areas agreed to increases of $3.5 million and $1.4 million, respectively. New rates became effective in August 2021.

In the normal course of business, Texas Gas Service has filed rate cases and sought GRIP and COSA increases in various other Texas jurisdictions to address investments in rate base and changes in expenses. For the years ended December 31, 2022 and 2021, the impact of these filings was not material.

Winter Storm Uri Deferred Costs - In accordance with regulatory orders associated with the winter weather event, our regulatory asset totaled approximately $258.2 million in extraordinary costs for natural gas purchases, related financing and carrying costs and other operational costs that have not been recovered at December 31, 2022. The amounts deferred include invoiced costs for natural gas purchases that have not been paid as we work with our suppliers to resolve discrepancies in invoiced amounts. The amounts deferred may be adjusted as the differences are resolved. As these amounts are related to the extraordinary gas purchase costs associated with Winter Storm Uri, which are deferred, future adjustments to the amounts deferred are not expected to have a material impact on earnings.

Other - Certain costs to be recovered through the ratemaking process have been capitalized as regulatory assets. Should recovery cease due to regulatory actions, certain of these assets may no longer meet the criteria for recognition and accordingly, a write-off of regulatory assets and stranded costs may be required. There were no write-offs of regulatory assets resulting from the failure to meet the criteria for capitalization during 2022, 2021 or 2020.

FINANCIAL RESULTS AND OPERATING INFORMATION

Selected Financial Results - Net income was $221.7 million, or $4.08 per diluted share, $206.4 million, or $3.85 per diluted share, and $196.4 million, or $3.68 per diluted share, for the years ended December 31, 2022, 2021 and 2020, respectively. We operate in one reportable business segment: regulated public utilities that deliver natural gas to residential, commercial and transportation customers. We evaluate our financial performance principally on net income.

The following table sets forth certain selected financial results for our operations for the periods indicated:

Financial Results	Years Ended December 31, 2022	2021	2020	Variances 2022 vs. 2021 Increase (Decrease)		Variances 2021 vs. 2020 Increase (Decrease)	
				(Millions of dollars, except percentages)			
Natural gas sales	**$ 2,418.7**	$ 1,661.7	$ 1,389.2	**$ 757.0**	**46 %**	$ 272.5	20 %
Transportation revenues	**126.5**	119.0	114.1	**7.5**	**6 %**	4.9	4 %
Other revenues	**32.8**	27.9	27.0	**4.9**	**18 %**	0.9	3 %
Total revenues	**2,578.0**	1,808.6	1,530.3	**769.4**	**43 %**	278.3	18 %
Cost of natural gas	**1,459.1**	775.0	537.4	**684.1**	**88 %**	237.6	44 %
Operating costs	**540.4**	516.1	494.5	**24.3**	**5 %**	21.6	4 %
Depreciation and amortization	**228.5**	207.2	194.9	**21.3**	**10 %**	12.3	6 %
Operating income	**$ 350.0**	$ 310.3	$ 303.5	**$ 39.7**	**13 %**	$ 6.8	2 %
Net income	**$ 221.7**	$ 206.4	$ 196.4	**$ 15.3**	**7 %**	$ 10.0	5 %
Capital expenditures and asset removal costs	**$ 656.5**	$ 544.3	$ 512.2	**$ 112.2**	**21 %**	$ 32.1	6 %

Natural gas sales to customers represent revenue from contracts with customers through implied contracts established by our tariffs and rates approved by regulatory authorities, as well as revenues from regulatory mechanisms related to natural gas sales. Additionally, natural gas sales includes recovery of the cost of natural gas.

Transportation revenues represent revenue from contracts with customers through implied contracts established by our tariffs and rates approved by regulatory authorities, as well as tariff-based negotiated contracts.

Other revenues include primarily miscellaneous service charges, which represent implied contracts with customers established by our tariffs and rates approved by regulatory authorities and other revenues from regulatory mechanisms.

Our average cost of gas rate increased to $8.22 per Mcf for the year ended December 31, 2022, compared to $4.87 per Mcf in the prior year. Cost of natural gas includes commodity purchases, fuel, storage, transportation, hedging costs and settlement proceeds for natural gas price volatility mitigation programs approved by our regulators and other gas purchase costs recovered through our cost of natural gas regulatory mechanisms and does not include an allocation of general operating costs or depreciation and amortization. These regulatory mechanisms provide a method of recovering natural gas costs on an ongoing basis without a profit. Therefore, although our revenues will fluctuate with the cost of natural gas that we pass-through to our customers, operating income is not affected by fluctuations in the cost of natural gas.

2022 vs. 2021 - Operating income increased $39.7 million due primarily to the following:
- an increase of $58.7 million from new rates;
- an increase of $7.0 million in residential sales due primarily to net customer growth; and
- a decrease of $3.1 million in bad debt expense.

These increases were offset partially by:
- an increase of $15.4 million in outside service costs;
- an increase of $14.1 million in depreciation expense due to additional capital expenditures being placed in service; and
- an increase of $3.2 million in employee-related costs.

Other Factors Affecting Net Income - Other factors that affect net income for the year ended December 31, 2022, compared with 2021, include an increase of $1.0 million in other expense, net, and an increase of $17.2 million in interest expense. The increase in other expense, net, is due primarily to a $10.9 million decrease in the market value of investments associated with our nonqualified employee benefit plans, offset partially by a $7.7 million decrease in net periodic benefit costs other than service costs. The increase in interest expense is due primarily to interest on our commercial paper, the issuance of $300 million of 4.25 percent senior notes in August 2022 and $336 million of 5.486 percent Securitized Utility Tariff Bonds in November 2022, compared with the same period last year.

EDIT - The return of EDIT to our customers is not expected to have a material impact on earnings, as any reduction or credit in rates is offset by a reduction in income tax expense. During the years ended December 31, 2022 and 2021, we credited income tax expense $18.0 million and $17.3 million, respectively, for the amortization of the regulatory liability associated with EDIT that was returned to customers.

Capital Expenditures and Asset Removal Costs - Our capital expenditures program includes expenditures for pipeline integrity, extending service to new areas, increasing system capabilities, pipeline replacements, automated meter reading, government-mandated pipeline relocations, fleet, facilities, IT assets and cybersecurity. It is our practice to maintain and upgrade our infrastructure, facilities and systems to ensure safe, reliable and efficient operations. Asset removal costs include expenditures associated with the replacement or retirement of long-lived assets that result from the construction, development and/or normal use of our assets, primarily our pipeline assets.

Capital expenditures and asset removal costs increased $112.2 million for 2022, compared with 2021, due primarily to expenditures for system integrity and extension of service to new areas. Our capital expenditures and asset removal costs are expected to be approximately $675 million for 2023. While we did not experience a significant impact to our capital expenditure program during the year ended December 31, 2022, our future capital expenditure activity is dependent on a number of factors, including economic conditions and our supply chains for contract labor, materials and supplies.

Selected Operating Information - The following tables set forth certain selected operating information for the periods indicated:

	Years Ended December 31,								Variances 2022 vs. 2021			
(in thousands)	2022				2021				Increase (Decrease)			
Average Number of Customers	**OK**	**KS**	**TX**	**Total**	**OK**	**KS**	**TX**	**Total**	**OK**	**KS**	**TX**	**Total**
Residential	**831**	**592**	**656**	**2,079**	824	591	650	2,065	**7**	**1**	**6**	**14**
Commercial and industrial	**76**	**50**	**35**	**161**	75	50	35	160	**1**	**—**	**—**	**1**
Other	**1**	**—**	**3**	**4**	—	—	3	3	**1**	**—**	**—**	**1**
Transportation	**5**	**6**	**1**	**12**	6	6	1	13	**(1)**	**—**	**—**	**(1)**
Total customers	**913**	**648**	**695**	**2,256**	905	647	689	2,241	**8**	**1**	**6**	**15**

	Years Ended December 31,								Variances 2021 vs. 2020			
(in thousands)	2021				2020				Increase (Decrease)			
Average Number of Customers	**OK**	**KS**	**TX**	**Total**	**OK**	**KS**	**TX**	**Total**	**OK**	**KS**	**TX**	**Total**
Residential	824	591	650	2,065	814	589	641	2,044	10	2	9	21
Commercial and industrial	75	50	35	160	75	50	35	160	—	—	—	—
Other	—	—	3	3	—	—	3	3	—	—	—	—
Transportation	6	6	1	13	6	6	1	13	—	—	—	—
Total customers	905	647	689	2,241	895	645	680	2,220	10	2	9	21

The increase in the average number of customers for 2022, compared with 2021, is due primarily to the connection of new customers resulting from the extension and expansion of our system in our service areas. For 2022, our average customer count includes 27,100 new customer connections compared to 24,900 in 2021.

The following table reflects the total volumes delivered, excluding the effects of WNA mechanisms:

Volumes *(MMcf)*	Years Ended December 31, 2022	2021	2020
Natural gas sales			
Residential	**125,286**	117,758	121,967
Commercial and industrial	**43,184**	37,615	36,169
Other	**2,725**	2,521	2,427
Total sales volumes delivered	**171,195**	157,894	160,563
Transportation	**230,080**	229,935	224,531
Total volumes delivered	**401,275**	387,829	385,094

Total sales volumes delivered increased for 2022, compared with 2021, due primarily to colder weather in the fourth quarter 2022. The impact of weather on residential and commercial natural gas sales is mitigated by WNA mechanisms in all jurisdictions.

The following table sets forth the HDDs by state for the periods indicated:

	Years Ended December 31,						
	2022		2021		2022 vs. 2021	2022	2021
HDDs	**Actual**	**Normal**	**Actual**	**Normal**	**Actual Variance**	**Actual as a percent of Normal**	
Oklahoma	**3,621**	**3,346**	3,224	3,229	**12 %**	**108 %**	100 %
Kansas	**4,779**	**4,722**	4,251	4,722	**12 %**	**101 %**	90 %
Texas	**1,950**	**1,764**	1,550	1,766	**26 %**	**111 %**	88 %

	Years Ended December 31,						
	2021		2020		2021 vs. 2020	2021	2020
HDDs	**Actual**	**Normal**	**Actual**	**Normal**	**Actual Variance**	**Actual as a percent of Normal**	
Oklahoma	3,224	3,229	3,253	3,264	(1)%	100 %	100 %
Kansas	4,251	4,722	4,408	4,722	(4)%	90 %	93 %
Texas	1,550	1,766	1,580	1,779	(2)%	88 %	89 %

Normal HDDs are established through rate proceedings in each of our rate jurisdictions for use primarily in weather normalization billing calculations. Normal HDDs disclosed above are based on:

- *Oklahoma* - For years 2021 through the current period, 10-year weighted average HDDs as of June 30, 2021, as calculated using 11 weather stations across Oklahoma and weighted on average customer count. For 2020, 10-year weighted average HDDs as of December 31, 2014, as calculated using 11 weather stations across Oklahoma and weighted on average customer count.
- *Kansas* - A 30-year rolling average for years 1988-2017 calculated using three weather stations across Kansas and weighted on HDDs by weather station and customers.
- *Texas* - An average of HDDs authorized in our most recent rate proceeding in each jurisdiction and weighted using a rolling 10-year average of actual natural gas distribution sales volumes by service area.

Actual HDDs are based on year-to-date, weighted average of:

- 11 weather stations and customers by month for Oklahoma;
- 3 weather stations and customers by month for Kansas; and
- 9 weather stations and natural gas distribution sales volumes by service area for Texas.

Selected financial results and operating information for 2021, compared with 2020, is described in Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report on Form 10-K for the year ended December 31, 2021.

CONTINGENCIES

We are a party to various litigation matters and claims that have arisen in the normal course of our operations. While the results of litigation and claims cannot be predicted with certainty, we believe the reasonably possible losses from such matters, individually and in the aggregate, are not material. Additionally, we believe the probable final outcome of such matters will not have a material adverse effect on our results of operations, financial position or cash flows. See Note 17 of the Notes to Consolidated Financial Statements in this Annual Report for information with respect to legal proceedings.

LIQUIDITY AND CAPITAL RESOURCES

General - We have relied primarily on operating cash flow and commercial paper for our liquidity and capital resource requirements. We fund operating expenses, working capital requirements, including purchases of natural gas, and capital expenditures primarily with cash from operations and commercial paper.

We believe that the combination of the significant residential component of our customer base, the fixed-charge component of our natural gas sales revenues and our rate mechanisms that we have in place result in a stable cash flow profile and historically has generated stable earnings. Additionally, we have rate mechanisms in place in our jurisdictions that reduce the lag in earning a return on our capital expenditures and provide for recovery of certain changes in our cost of service by allowing for adjustments to rates between rate cases. We anticipate that our cash flow generated from operations and our expected short- and long-term financing arrangements will enable us to maintain our current and planned level of operations and provide us flexibility to finance our infrastructure investments. Our ability to access capital markets for debt and equity financing under reasonable terms depends on market conditions, our financial condition and credit ratings.

Short-term Debt - On March 16, 2022, we entered into the first amendment to the second amended and restated ONE Gas Credit Agreement, which was previously amended and restated on March 16, 2021. The amendment extends the maturity date of the ONE Gas Credit Agreement to March 16, 2027, from March 16, 2026, and amends the ONE Gas Credit Agreement to provide that we may extend the maturity date, subject to the lenders' consent, by one year two additional times. The amendment also changes the benchmark rate defined in the ONE Gas Credit Agreement to SOFR. All other material terms and conditions of the ONE Gas Credit Agreement remain in full force and effect.

The ONE Gas Credit Agreement provides for a $1.0 billion revolving unsecured credit facility and includes a $20 million letter of credit subfacility and a $60 million swingline subfacility. We can request an increase in commitments of up to an additional $500 million upon satisfaction of customary conditions, including receipt of commitments from either new lenders or increased commitments from existing lenders. The ONE Gas Credit Agreement is available to provide liquidity for working capital, capital expenditures, acquisitions and mergers, the issuance of letters of credit and for other general corporate purposes.

The ONE Gas Credit Agreement contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining ONE Gas' total debt-to-capital ratio of no more than 70 percent at the end of any calendar quarter. At December 31, 2022, our total debt-to-capital ratio was 56 percent and we were in compliance with all covenants under the ONE Gas Credit Agreement. We may reduce the unutilized portion of the ONE Gas Credit Agreement in whole or in part without premium or penalty. The ONE Gas Credit Agreement contains customary events of default. Upon the occurrence of certain events of default, the obligations under the ONE Gas Credit Agreement may be accelerated and the commitments may be terminated.

In connection with the second amendment and restatement of the ONE Gas Credit Agreement on March 16, 2021, all commitments under the ONE Gas 364-day Credit Agreement were terminated and all obligations under the ONE Gas 364-day Credit Agreement were paid in full and discharged.

In June 2021, we increased the size of our commercial paper program to permit the issuance of commercial paper to fund short-term borrowing needs in an aggregate principal amount not to exceed $1.0 billion outstanding at any time. Prior to this increase, our commercial paper program permitted us to issue commercial paper in an aggregate principal amount not to exceed $700 million outstanding at any time. The maturities of the commercial paper notes may vary but may not exceed 270 days from the date of issue. Commercial paper is generally sold at par less a discount representing an interest factor. At December 31, 2022 and 2021, we had $552.0 million and $494.0 million of commercial paper outstanding, respectively. The weighted-average interest rate on our commercial paper was 4.75 percent and 0.38 percent at December 31, 2022 and 2021, respectively.

At December 31, 2022, we had $1.2 million in letters of credit issued and no borrowings under the ONE Gas Credit Agreement, with $998.8 million of remaining credit available to repay our commercial paper borrowings.

Long-term Debt - On August 8, 2022, we issued $300 million of 4.25 percent senior notes due September 2032. The proceeds from the issuance were used to repay amounts outstanding under our commercial paper program and for general corporate purposes.

On August 25, 2022, the ODFA completed the issuance of $1.35 billion in ratepayer-backed bonds with varying scheduled final maturities over 30 years, consistent with the OCC financing order. The bonds are limited and special revenue obligations of the ODFA, payable solely from the securitization bond collateral and are not an obligation of Oklahoma Natural Gas or any of its affiliates.

The proceeds received by Oklahoma Natural Gas were approximately $1.3 billion, which represents the amount of the securitization bonds issued by the ODFA less issuance costs. The receipt of these proceeds represents Oklahoma Natural Gas' recovery of the approximately $1.3 billion of authorized extraordinary natural gas purchase costs and other operational costs incurred during Winter Storm Uri, as well as carrying costs.

In August 2022, we called $750 million of the $1.0 billion of 0.85 percent senior notes due March 2023, $150 million of the $700 million of 1.10 percent senior notes due March 2024 and the remaining $400 million of outstanding floating-rate senior notes due March 2023, using the proceeds received from Oklahoma Natural Gas' securitization transaction.

On November 18, 2022, KGSS-I issued $336 million of 5.486 percent Securitized Utility Tariff Bonds. The Securitized Utility Tariff Bonds have an interest rate of 5.486 percent and a term of 10 years with semi-annual principal repayments, which results in an expected weighted average life of the bonds of 5.5 years. The bonds are governed by an indenture between KGSS-I and the indenture trustee. The indenture contains certain covenants that restrict KGSS-I's ability to sell, transfer, convey, exchange, or otherwise dispose of its assets.

In November 2022, we called the remaining $250 million of the $1.0 billion of 0.85 percent senior notes due March 2023 and $77 million of the $700 million of 1.10 percent senior notes due March 2024, using the proceeds from the securitization transaction for Kansas Gas Service. See Note 10 of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of the securitization transactions.

In March 2021, we issued $1.0 billion of 0.85 percent senior notes due March 2023, $700 million of 1.10 percent senior notes due March 2024, and $800 million of floating-rate senior notes due March 2023. The net proceeds from the issuance were used for payment of gas purchases and related costs resulting from Winter Storm Uri and general corporate purposes.

In September 2021, we called $400 million of the floating-rate senior notes due March 2023 at par, using a combination of cash on hand and commercial paper. We did not have the right to call these senior notes prior to September 11, 2021.

The indenture governing our Senior Notes includes an event of default upon the acceleration of other indebtedness of $100 million or more. Such events of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of the outstanding Senior Notes to declare those Senior Notes immediately due and payable in full.

Depending on the series, we may redeem our Senior Notes at par, plus accrued and unpaid interest to the redemption date, starting three months or six months before their maturity dates. Prior to these dates, we may redeem these Senior Notes, in whole or in part, at a redemption price equal to the principal amount, plus accrued and unpaid interest and a make-whole premium. The redemption price will never be less than 100 percent of the principal amount of the respective Senior Note plus accrued and unpaid interest to the redemption date. Our Senior Notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness.

In February 2021, we entered into the ONE Gas 2021 Term Loan Facility as part of the financing of our natural gas purchases in order to provide sufficient liquidity to satisfy our obligations as a result of Winter Storm Uri. The net proceeds of the March 2021 debt issuance reduced the commitments under the ONE Gas 2021 Term Loan Facility on a dollar-for-dollar basis, and as a result no commitments remained outstanding and the facility was terminated concurrently with the closing of the debt issuance.

At December 31, 2022, our long-term debt-to-capital ratio was 51 percent.

Credit Ratings - Our credit ratings at December 31, 2022, were:

Rating Agency	Rating	Outlook
Moody’s	A3	Stable
S&P	A-	Stable

At December 31, 2022, our commercial paper was rated Prime-2 by Moody’s and A-2 by S&P. We intend to maintain credit metrics at a level that supports our balanced approach to capital investment and a return of capital to shareholders via a dividend that we believe will be competitive with our peer group.

At-the-Market Equity Program - In February 2020, we initiated an at-the-market equity program by entering into an equity distribution agreement under which we may issue and sell shares of our common stock with an aggregate offering price up to $250 million (including any shares of common stock that may be sold pursuant to the master forward sale confirmation entered into in connection with the equity distribution agreement and the related supplemental confirmations). Sales of common stock are made by means of ordinary brokers’ transactions on the NYSE, in block transactions or as otherwise agreed to between us and the sales agent. We are under no obligation to offer and sell common stock under the program.

For the years ended December 31, 2022 and 2021, we sold and issued 403,792 and 281,124 shares of our common stock for $35.0 million and $21.4 million, respectively, generating proceeds, net of issuance costs, of $34.7 million and $21.1 million, respectively.

For the year ended December 31, 2022, we also executed forward sale agreements for 1,451,474 shares of our common stock. We did not enter into any forward sale agreements in 2021. On December 30, 2022, we settled forward sales agreements with respect to 1,162,071 shares of our common stock for net proceeds of $93.8 million. Had we settled the remaining 289,403 shares under the outstanding forward sale agreements as of December 31, 2022, we would have generated net proceeds of approximately $21.7 million.

At December 31, 2022, we had $63.1 million of equity available for issuance under the program.

Pension and Other Postemployment Benefit Plans - For the year ended December 31, 2022, we contributed $1.5 million to our defined benefit pension plans and $1.9 million to our other postemployment benefit plans. For the year ended December 31, 2021, we contributed $1.0 million to our defined benefit pension plans and $2.0 million to our other postemployment benefit plans. Additional information about our pension and other postemployment benefits plans, including anticipated contributions, is included under “Estimates and Critical Accounting Policies - Pension and Other Postemployment Benefits” and under Note 14 of the Notes to Consolidated Financial Statements in this Annual Report.

CASH FLOW ANALYSIS

We use the indirect method to prepare our consolidated statements of cash flows. Under this method, we reconcile net income to cash flows provided by operating activities by adjusting net income for those items that impact net income but may not result in actual cash receipts or payments and changes in our assets and liabilities not classified as investing or financing activities during the period. Items that impact net income but may not result in actual cash receipts or payments include, but are not limited to, depreciation and amortization, deferred income taxes, share-based compensation expense and provision for doubtful accounts.

The following table sets forth the changes in cash flows by operating, investing and financing activities for the periods indicated:

	Years Ended December 31,			Variances	
	2022	2021	2020	2022 vs. 2021	2021 vs. 2020
			(*Millions of dollars*)		
Total cash provided by (used in):					
Operating activities	**1,570.8** $	(1,535.7) $	364.5	$ **3,106.5** $	(1,900.2)
Investing activities	**(614.1)**	(501.1)	(470.4)	$ **(113.0)**	(30.7)
Financing activities	**(947.4)**	2,037.6	96.0	**(2,985.0)**	1,941.6
Change in cash, cash equivalents, restricted cash and restricted cash equivalents	**9.3**	0.8	(9.9)	**8.5**	10.7
Cash, cash equivalents, restricted cash and restricted cash equivalents at beginning of period	**8.8**	8.0	17.9	**0.8**	(9.9)
Cash, cash equivalents, restricted cash and restricted cash equivalents at end of period	**$ 18.1** $	8.8 $	8.0	$ **9.3** $	0.8

Operating Cash Flows - Changes in cash flows from operating activities are due primarily to changes in operating income and expenses discussed in "Financial Results and Operating Information," the effects of tax reform discussed in "Regulatory Activities" and changes in working capital. Changes in natural gas prices and demand for our services or natural gas, whether because of general economic conditions, variations in weather not mitigated by WNAs, changes in supply or increased competition from other energy providers, could affect our earnings and operating cash flows. Typically, our cash flows from operations are greater in the first half of the year compared with the second half of the year.

2022 vs. 2021 - Cash flows from operating activities were higher in 2022 compared with 2021, due primarily to recovery of regulatory assets associated with Winter Storm Uri, through securitization in Oklahoma compared to increased natural gas purchases and other extraordinary costs in the prior period resulting from Winter Storm Uri, which were deferred and included in regulatory assets. See Notes 10 and 11 of the Notes to Consolidated Financial Statements in this Annual Report for additional information.

Investing Cash Flows - 2022 vs. 2021 - Cash used in investing activities increased for 2022, compared to 2021, due primarily to an increase in capital expenditures for system integrity and extension of service to new areas.

Financing Cash Flows - 2022 vs. 2021 - Cash flows from financing activities were lower in 2022 compared with 2021, due primarily to a net outflow of cash for repayments of long-term debt in 2022 compared to a net inflow of cash from issuances of long-term debt in 2021. See Notes 4 and 11 of the Notes to Consolidated Financial Statements in this Annual Report for additional information.

2021 vs. 2020 - Cash flows in 2021, compared with 2020, are described in Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report on Form 10-K for the year ended December 31, 2021.

ENVIRONMENTAL, SAFETY AND REGULATORY MATTERS

Environmental Matters - We are subject to multiple laws and regulations regarding protection of the environment and natural and cultural resources, which affect many aspects of our present and future operations. Regulated activities include, but are not limited to, those involving air emissions, storm water and wastewater discharges, handling and disposal of solid and hazardous wastes, wetland preservation, plant and wildlife protection, hazardous materials use, storage and transportation, and pipeline and facility construction. These laws and regulations require us to obtain and/or comply with a wide variety of environmental clearances, registrations, licenses, permits and other approvals. Failure to comply with these laws, regulations, licenses and permits or the discovery of presently unknown environmental conditions may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations. In addition, emission controls and/or other regulatory or permitting mandates under the CAA and other similar federal and state laws could require unexpected capital expenditures. We cannot assure that existing environmental statutes and regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional statutes or regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial condition and results of operations. Our expenditures for environmental investigation and remediation compliance to-date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters had no material effects on earnings or cash flows during 2022, 2021 and 2020.

We own or retain legal responsibility for certain environmental conditions at 12 former MGP sites in Kansas. These sites contain contaminants generally associated with MGP sites and are subject to control or remediation under various environmental laws and regulations. A consent agreement with the KDHE governs all environmental investigation and remediation work at these sites. The terms of the consent agreement require us to investigate these sites and set remediation activities based upon the results of the investigations and risk analysis. Remediation typically involves the management of contaminated soils and may involve removal of structures and monitoring and/or remediation of groundwater. Regulatory closure has been achieved at five of the 12 sites, but these sites remain subject to potential future requirements that may result in additional costs.

We have an AAO that allows Kansas Gas Service to defer and seek recovery of costs necessary for investigation and remediation at, and nearby, these 12 former MGP sites that are incurred after January 1, 2017, up to a cap of $15.0 million, net of any related insurance recoveries. Costs approved for recovery in a future rate proceeding would then be amortized over a 15-year period. The unamortized amounts will not be included in rate base or accumulate carrying charges. Following a determination that future investigation and remediation work approved by the KDHE is expected to exceed $15.0 million, net of any related insurance recoveries, Kansas Gas Service will be required to file an application with the KCC for approval to increase the $15.0 million cap. At December 31, 2022 and 2021, we have deferred $29.8 million and $29.9 million, respectively, for accrued investigation and remediation costs pursuant to our AAO. Kansas Gas Service expects to file an application as soon as practicable after the KDHE approves the plans we have submitted.

We have completed or are addressing removal of the source of soil contamination at all 12 sites and continue to monitor groundwater at seven of the 12 sites according to plans approved by the KDHE. In 2019, we completed a project to remove a source of contamination and associated contaminated materials at the twelfth site where no active soil remediation had previously occurred. Remediation plans concerning various sites were submitted to the KDHE in 2021 and 2020 and the KDHE has provided comments that we are addressing. We are also working on a remediation plan for another of these sites for submission to the KDHE.

We also own or retain legal responsibility for certain environmental conditions at a former MGP site in Texas. At the request of the TCEQ, we began investigating the level and extent of contamination associated with the site under their Texas Risk Reduction Program. A preliminary site investigation revealed that this site contains contaminants generally associated with MGP sites and is subject to control or remediation under various environmental laws and regulations. Impacts have been identified in the soil and groundwater at the site with limited impacts observed in surrounding areas. In April 2022, we submitted a remediation work plan to address the areas impacted to the TCEQ. At December 31, 2022, estimated costs associated with expected remediation activities for this site are not material.

Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters had no material effects on earnings or cash flows during the years ended December 31, 2022, 2021 and 2020. The reserve for remediation of our MGP sites was $12.7 million and $22.8 million at December 31, 2022 and December 31, 2021, respectively. Environmental issues may exist with respect to MGP sites that are unknown to us. Accordingly, future costs are dependent on the final determination and regulatory approval of any remedial actions, the complexity of the site, level of remediation required, changing technology and governmental regulations, and to the extent not recovered by insurance or recoverable in rates from our customers, could be material to our financial condition, results of operations or cash flows.

We are subject to environmental regulation by federal, state and local authorities. Due to the inherent uncertainties surrounding the development of federal and state environmental laws and regulations, we cannot determine with specificity the impact such laws and regulations may have on our existing and future facilities. With the trend toward stricter standards, greater regulation and more extensive permit requirements for the types of assets operated by us, our environmental expenditures could increase in the future, and such expenditures may not be fully recovered by insurance or recoverable in rates from our customers, and those costs may adversely affect our financial condition, results of operations and cash flows.

Environmental Footprint - Our environmental and climate change strategy focuses on taking steps to minimize the impact of our operations on the environment. These strategies include: (1) developing and maintaining an accurate greenhouse gas emissions inventory according to current rules issued by the EPA; (2) monitoring and improving the integrity of our pipelines; (3) reducing operational emissions through the implementation of advanced leak detection technology and damage prevention programs; (4) promoting end-use conservation through programs that incentivize the use of high-efficiency equipment; and (5) increased utilization of CNG for vehicles. In addition, we are considering potential avenues to incorporate RNG and hydrogen into our operations. RNG and hydrogen technologies offer potential opportunities to secure lower-carbon supply sources that could be transported on our pipeline system and potentially reduce the carbon intensity of the product we deliver.

We participate in several programs to voluntarily reduce methane emissions including the EPA's Natural Gas STAR Program, the EPA's Natural Gas STAR Methane Challenge Program, and Our Nation's Energy Future (ONE Future). By joining these programs, we committed to: (1) evaluate our methane emission reduction opportunities; (2) implement practices to reduce methane emissions where feasible; and (3) annually report our methane emissions and/or our methane reduction activities. As part of the Methane Challenge Program, we have committed to annually replace or rehabilitate at least two percent of our combined inventory of cast iron and noncathodically-protected steel pipe, which aligns with our planned system integrity expenditures for infrastructure replacements. We exceeded our goal by achieving an overall replacement rate greater than two percent annually every year from 2016 through 2021 and anticipate reporting on our 2022 progress in 2023.

In September 2020, we announced membership in ONE Future, a group of natural gas companies working together to voluntarily reduce methane emissions across the natural gas value chain to one percent or less by 2025. We have submitted our 2020 and 2021 data, which ONE Future aggregates with peer members. In its most recent annual report, ONE Future stated that its members registered a 2021 methane intensity of 0.462 percent, which surpassed the 2025 goal of 1.0 percent. The intensity for the distribution sector, which includes us, was 0.113 percent, beating the 2021 goal of 0.225 percent by 50 percent. Participating distribution companies represented 47 percent of the natural gas delivered in the U.S. in 2021.

Additional information about our environmental matters is included in the section entitled "Environmental Matters" in Note 17 of the Notes to Consolidated Financial Statements in this Annual Report. We cannot assure that existing environmental statutes and regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial condition and results of operations. Our expenditures for environmental investigation, and remediation compliance to-date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters had no material effects on earnings or cash flows during 2022, 2021 or 2020.

Pipeline Safety - We are subject to regulation under federal pipeline safety statutes and any analogous state regulations. These include safety requirements for the design, construction, operation, and maintenance of pipelines, including transmission and distribution pipelines. At the federal level, we are regulated by PHMSA. PHMSA regulations require the following for certain pipelines: inspection and maintenance plans; integrity management programs, including the determination of pipeline integrity risks and periodic assessments on certain pipeline segments; an operator qualification program, which includes certain trainings; a public awareness program that provides certain information; and a control room management plan.

As part of regulating pipeline safety, PHMSA promulgates various regulations. In April 2016, PHMSA published a NPRM, the Safety of Gas Transmission & Gathering Lines Rule, in the Federal Register to revise pipeline safety regulations applicable to the safety of onshore natural gas transmission and gathering pipelines. Proposals included changes to pipeline integrity management requirements and other safety-related requirements, which were split into three separate rulemakings. At December 31, 2022, all three final rules have been published and the potential capital and operating expenditures associated with compliance were not material or did not apply to us.

Separately, as part of the Consolidated Appropriations Act, 2021, the PIPES Act of 2020 reauthorized PHMSA through 2023 and directed the agency to move forward with several regulatory actions, including the "Pipeline Safety: Class Location Change Requirements" and the "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines" proposed rulemakings. Congress has also instructed PHMSA to issue final regulations that will require operators of non-rural gas gathering lines and new and existing transmission and distribution pipeline facilities to conduct certain leak detection and repair programs and to require facility inspection and maintenance plans to align with those regulations. To the extent such rulemakings impose more stringent requirements on our facilities, we may be required to incur expenditures that may be material.

Air and Water Emissions - The CAA, the Clean Water Act, and analogous state laws and/or regulations promulgated thereunder, impose restrictions and controls regarding the discharge of pollutants into the air and water in the United States. Failure to comply with these requirements may result in substantial fines or other penalties, including (in certain cases) the revocation of necessary permits. Under the CAA, a federally enforceable operating permit is required for sources of significant air emissions. We may be required to incur certain capital expenditures for air-pollution-control equipment in connection with obtaining or maintaining permits and approvals for sources of air emissions. Such expenditures have not had a material impact on our results of operations, financial position or cash flows; however, we cannot predict the impacts of any future requirements. The Clean Water Act imposes substantial potential liability for the discharge of pollutants into waters of the United States, including the potential for fines, civil enforcement, or orders to perform remediation of waters affected by such discharge.

Climate – The threat of climate change continues to attract considerable attention. International, federal, state and/or local statute and/or regulatory initiatives may be proposed in the future to regulate greenhouse gas emissions. We monitor relevant legislation and regulatory initiatives to assess the potential impact on our operations. On August 16, 2022, the IRA of 2022 was signed into law. The IRA of 2022 contains approximately $369 billion in climate funding, largely consisting of tax credits for clean energy. Based upon our review of the legislation, we do not anticipate it to have any material impacts on our future results of operations.

The EPA's Mandatory Greenhouse Gas Reporting Rule requires annual greenhouse gas emissions reporting as carbon dioxide equivalents from affected facilities and for the natural gas delivered by us to our natural gas distribution customers who are not otherwise required to report their own emissions. The additional cost to gather and report this emission data did not have, and we do not expect it to have, a material impact on our results of operations, financial position or cash flows. In addition, Congress has considered, and may consider in the future, legislation to reduce greenhouse gas emissions, including carbon dioxide and methane. While the IRA of 2022 imposes a charge on methane emissions from certain facilities, the charge does not apply to distribution companies such as ONE Gas. Likewise, the EPA may institute additional regulatory rulemaking associated with greenhouse gas emissions. At this time, no rule or legislation has been enacted for natural gas distribution that assesses any costs, fees or expenses on any of these emissions.

Our operations may also be indirectly impacted by regulations attempting to limit or control climate impacts. For example, there is a risk that financial institutions may be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. Recently, President Biden signed an executive order calling for the development of a climate finance plan and, separately, the Federal Reserve announced that it has joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector.

Waste and Hazardous Substances - During the course of our operations, we may use or generate hazardous substances and wastes, including hazardous wastes. The generation, use, storage, transportation, handling, and disposal of such materials may be subject to federal, state, and local laws. For example, the Resource Conservation and Recovery Act regulates both solid and hazardous wastes, including the imposition of detailed requirements for the handling, storage, treatment, and disposal of hazardous wastes. Separately, CERCLA, also commonly known as Superfund, imposes strict, joint and several liability, without regard to fault or the legality of the original act, on certain classes of "persons" (defined under CERCLA). These persons include, but are not limited to, the owner or operator of a facility where the release occurred and/or companies that disposed or arranged for the disposal of the hazardous substances found at the facility. Under CERCLA, these persons may be liable for the costs of cleaning up the hazardous substances released into the environment, damages to natural resources and the costs of certain health studies.

Pipeline Security - In May and July 2021, TSA issued security directives which included several new cybersecurity requirements for critical pipeline owners and operators. The first security directive requires critical pipeline owners and operators to (1) report confirmed and potential cybersecurity incidents to the CISA; (2) designate a cybersecurity coordinator to be available 24 hours a day, seven days a week; (3) review current practices; and (4) identify any gaps and related remediation measures to address cyber-related risks and report the results to TSA and CISA within 30 days. The second security directive requires owners and operators of TSA-designated critical pipelines to implement specific mitigation measures to protect against ransomware and other known threats to information technology and operational technology systems, develop and implement a cybersecurity contingency and recovery plan, and conduct a cybersecurity architecture design review. Compliance with these measures has not had a material impact on our operations. We continue to evaluate the potential effect of these directives on our operations and facilities, as well as the potential cost of implementation, and will continue to monitor for any clarifications or amendments to these directives.

COVID-19 - Throughout the COVID-19 pandemic, we continued to provide essential services to our customers. We implemented a comprehensive set of policies, procedures and guidelines to protect the safety of our employees, customers and communities. Safety protocols developed during the pandemic include remote work for our office-based employees, limiting direct contact with our customers and requiring the use of PPE and a self-assessment health screening mobile application.

Impacts on our results of operations as a result of COVID-19 include but are not limited to:

- lower late payment, reconnect and collection fees and incremental expenses for bad debts related to the suspension of disconnects for nonpayment until the second quarter of 2021;
- incremental expenses for PPE, cleaning supplies, outside services and other expenses; and
- lower expenses for travel and employee training that have been impacted by the pandemic.

We received accounting orders in each of our jurisdictions authorizing us to accumulate and defer for regulatory purposes certain incremental costs incurred, including bad debt expenses, and certain lost revenues, net of offsetting expense reductions associated with COVID-19. Recovery of any net incremental costs and lost revenue deferred pursuant to these orders will be determined in future rate cases or alternative rate recovery filings in each jurisdiction. At December 31, 2022, we have not requested recovery of any deferrals pursuant to these orders and no regulatory assets have been recorded.

Regulatory - Several regulatory initiatives impacted the earnings and future earnings potential of our business. See additional information regarding our regulatory initiatives in "Regulatory Activities" in Management's Discussion and Analysis of Financial Condition and Results of Operations.

IMPACT OF NEW ACCOUNTING STANDARDS

Information about the impact of new accounting standards is included in Note 1 of the Notes to Consolidated Financial Statements in this Annual Report.

CRITICAL ESTIMATES AND ACCOUNTING POLICIES

The preparation of our consolidated financial statements and related disclosures in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions that cannot be known with certainty that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. These estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Although we believe these estimates and assumptions are reasonable, actual results could differ from our estimates. See our "Risk Factors" and/or "Forward-Looking Statements" in this Annual Report for factors which could impact our estimates.

The following summary sets forth what we consider to be our most critical estimates and accounting policies. Our critical accounting policies are defined as those estimates and policies most important to the portrayal of our financial condition and results of operations and that require management's most difficult, subjective or complex judgment, particularly because of the need to make estimates concerning the impact of inherently uncertain matters.

Regulation - Our operations are subject to regulation with respect to rates, service, maintenance of pipeline and accounting records and various other matters by the respective regulatory authorities in the states in which we operate. We account for the financial effects of the ratemaking and accounting practices and policies of the various regulatory authorities in our consolidated financial statements. We record regulatory assets for costs that have been deferred for which future recovery through customer rates is considered probable and regulatory liabilities when it is probable that revenues will be reduced for amounts that will be returned to customers through the ratemaking process. As a result, certain costs that would normally be expensed under GAAP are capitalized or deferred on the balance sheet because it is probable they can be recovered through rates. Discontinuing the application of this method of accounting for regulatory assets and liabilities could significantly increase our operating expenses, as fewer costs would likely be capitalized or deferred on the balance sheet, which could reduce our net income. Further, regulation may impact the period in which revenues or expenses are recognized. The amounts to be recovered or recognized are based upon historical experience and our understanding of the regulations. The impact of regulation on our operations may be affected by decisions of the regulatory authorities or the issuance of new regulations.

For further discussion of regulatory assets and liabilities, see Note 10 of the Notes to Consolidated Financial Statements in this Annual Report.

Revenue Recognition - For regulated deliveries of natural gas, we read meters and bill customers on a monthly cycle. We recognize revenues upon the delivery of natural gas or services rendered to customers. The billing cycles for customers do not necessarily coincide with the accounting periods used for financial reporting purposes. We accrue unbilled revenues for natural gas that has been delivered but not yet billed at the end of an accounting period. Accrued unbilled revenue is based on a percentage estimate of amounts unbilled each month, which is dependent upon a number of factors, some of which require management's judgment. These factors include customer consumption patterns and the impact of weather on usage. The accrued unbilled natural gas sales revenue at December 31, 2022 and 2021 was $269.5 million and $183.2 million, respectively, and is included in accounts receivable on our consolidated balance sheets.

We have determined the majority of our natural gas sales and transportation tariffs to be implied contracts with customers, which are settled over time, where our performance obligation is settled with our customer when natural gas is delivered and simultaneously consumed by the customer. In addition, we use the invoice method practical expedient, where we recognize revenue for volumes delivered for which we have a right to invoice. For our other utility revenue, which are primarily one-time service fees that meet the requirements under ASC 606, the performance obligation is satisfied at a point in time when services are rendered to the customer. Certain revenues that do not meet the requirements under ASC 606 as revenues from contracts with customers are reflected as other revenues in determining total revenue. See Note 2 of the Notes to Consolidated Financial Statements in this Annual Report for additional information regarding our revenues.

Pension and Other Postemployment Benefits - We have defined benefit pension plans covering eligible retirees and full-time employees. We also sponsor welfare plans that provide other postemployment medical and life insurance benefits to eligible retirees and employees who retire with at least five years of service.

To calculate the expense and liabilities related to our plans, we utilize an outside actuarial consultant, which uses statistical and other factors to anticipate future events. These factors include assumptions about the discount rate, expected return on plan assets, rate of future compensation increases, age and mortality and employment periods. We use tables issued by the Society of Actuaries to estimate mortality rates. In determining the projected benefit costs, assumptions can change from period to period and may result in material changes in the costs and liabilities we recognize.

For the year ended December 31, 2022, we contributed $1.5 million to our defined benefit pension plans and $1.9 million to our other postemployment benefit plans. For the year ended December 31, 2021, we contributed $1.0 million to our defined benefit pension plans and $2.0 million to our other postemployment benefit plans. In 2023, our contributions are expected to be $1.4 million to our defined benefit pension plans, and no contributions are expected to be made to our other postemployment benefit plans.

We recorded net periodic benefit costs for our defined benefit pension plans, prior to regulatory deferrals, of $5.0 million in 2022, and estimate that in 2023, we will record a credit of approximately $7.5 million. Net periodic benefits costs for our postemployment benefit plans, prior to regulatory deferrals, were a credit of $5.2 million in 2022, and we estimate that in 2023, we will record expense of approximately $0.3 million, prior to regulatory deferrals.

The following table sets forth the significant assumptions used to determine our estimated 2023 net periodic benefit cost related to our defined benefit pension and other postemployment benefit plans and sensitivity to changes with respect to these assumptions:

	Rate Used	Cost Sensitivity (a)	Obligation Sensitivity (b)
		(*Millions of dollars*)	
Discount rate for pension	**5.60 %**	**$ 2.3**	**$ 20.9**
Discount rate for other postemployment benefits	**5.70 %**	**$ (0.1)**	**$ 3.6**
Expected long-term return on plan assets for pension	**6.75 %**	**$ 2.2**	**$ —**
Expected long-term return on plan assets for other postemployment benefits	**5.55 %**	**$ 0.4**	**$ —**

(a) Approximate impact a quarter percentage point decrease in the assumed rate would have on net periodic pension costs.
(b) Approximate impact a quarter percentage point decrease in the assumed rate would have on defined benefit pension obligation.

See Note 14 of the Notes to Consolidated Financial Statements in this Annual Report for additional information regarding our pension and other postretirement benefit plans.

Contingencies - Our accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be reasonably estimated. We expense legal fees as incurred and base our legal liability estimates on currently available facts and our assessments of the ultimate outcome or resolution. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than the completion of a remediation feasibility study. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable.

Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters had no material effect on earnings or cash flows for the years ended December 31, 2022, 2021 and 2020. Environmental issues may exist with respect to these MGP sites that are unknown to us. Accordingly, future costs are dependent on the final determination and regulatory approval of any remedial actions, the complexity of the site, level of remediation required, changing technology and governmental regulations, and to the extent not recovered by insurance or recoverable in rates from our customers, could be material to our financial condition, results of operations or cash flows.

See “Environmental Matters” and Note 17 of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of contingencies.

CONTRACTUAL OBLIGATIONS

Long-term debt, commercial paper borrowings and interest payments on debt - Long-term debt includes our Senior Notes and Securitized Utility Tariff Bonds. See Notes 3 and 4 in the Notes to Consolidated Financial Statements in this Annual Report for additional information on our long-term debt, commercial paper borrowings and interest payments on our debt. Interest payments on debt are calculated by multiplying our long-term debt by the respective coupon rates or effective floating rate.

Firm transportation and storage contracts - We are party to fixed-price contracts providing us with firm transportation and storage capacity. The commitments associated with these contracts are recoverable through our purchased-gas cost mechanisms as allowed by the applicable regulatory authority.

Natural gas purchase commitments - We are party to fixed-price and variable-price contracts for the purchase of natural gas. Future variable-price natural gas purchase commitments are estimated based on market price information as of December 31, 2022. Actual future variable-price purchase commitments may vary depending on market prices at the time of delivery. As market information changes daily and is potentially volatile, these values may change significantly. The commitments associated with these contracts are recoverable through our purchased-gas cost mechanisms as allowed by the applicable regulatory authority.

Operating leases - Our operating leases consist primarily of office facilities and IT leases. See Note 5 of the Notes to Consolidated Financial Statements in this Annual Report for discussion of leases.

FORWARD-LOOKING STATEMENTS

Some of the statements contained and incorporated in this Annual Report are forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. The forward-looking statements relate to our anticipated financial performance, liquidity, management’s plans and objectives for our future operations, our business prospects, the outcome of regulatory and legal proceedings, market conditions and other matters. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. The following discussion is intended to identify important factors that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking statements include the items identified in the preceding paragraph, the information concerning possible or assumed future results of our operations and other statements contained or incorporated in this Annual Report identified by words such as “anticipate,” “estimate,” “expect,” “project,” “intend,” “plan,” “believe,” “should,” “goal,” “forecast,” “guidance,” “could,” “may,” “continue,” “might,” “potential,” “scheduled,” “likely,” and other words and terms of similar meaning.

One should not place undue reliance on forward-looking statements, which are applicable only as of the date of this Annual Report. Known and unknown risks, uncertainties and other factors may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by forward-looking statements. Those factors may affect our operations, costs, liquidity, markets, products, services and prices. In addition to any assumptions and other factors referred to specifically in connection with the forward-looking statements, factors that could cause our actual results to differ materially from those contemplated in any forward-looking statement include, among others, the following:

- our ability to recover costs (including operating costs and increased commodity costs related to Winter Storm Uri in February 2021), income taxes and amounts equivalent to the cost of property, plant and equipment, regulatory assets and our allowed rate of return in our regulated rates or other recovery mechanisms;
- cyber-attacks, which, according to experts, have increased in volume and sophistication since the beginning of the COVID-19 pandemic, or breaches of technology systems that could disrupt our operations or result in the loss or exposure of confidential or sensitive customer, employee or Company information; further, increased remote working arrangements as a result of the pandemic have required enhancements and modifications to our IT infrastructure (e.g. Internet, Virtual Private Network, remote collaboration systems, etc.), and any failures of the technologies, including third-party service providers, that facilitate working remotely could limit our ability to conduct ordinary operations or expose us to increased risk or effect of an attack;
- our ability to manage our operations and maintenance costs;

- the concentration of our operations in Oklahoma, Kansas, and Texas;
- changes in regulation of natural gas distribution services, particularly those in Oklahoma, Kansas and Texas;
- the economic climate and, particularly, its effect on the natural gas requirements of our residential and commercial customers;
- the length and severity of a pandemic or other health crisis, such as the outbreak of COVID-19, including the impact to our operations, customers, contractors, vendors and employees, the effectiveness of vaccine campaigns (including the COVID-19 vaccine campaign) on our workforce and customers and the effect of other measures or mandates that international, federal, state and local governments, agencies, law enforcement and/or health authorities implement to address the pandemic or other health crisis, which could (as with COVID-19) precipitate or exacerbate one or more of the above-mentioned and/or other risks, and significantly disrupt or prevent us from operating our business in the ordinary course for an extended period;
- competition from alternative forms of energy, including, but not limited to, electricity, solar power, wind power, geothermal energy and biofuels;
- adverse weather conditions and variations in weather, including seasonal effects on demand and/or supply, the occurrence of severe storms in the territories in which we operate, and climate change, and the related effects on supply, demand, and costs;
- indebtedness could make us more vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds and/or place us at competitive disadvantage compared with competitors;
- our ability to secure reliable, competitively priced and flexible natural gas transportation and supply, including decisions by natural gas producers to reduce production or shut-in producing natural gas wells and expiration of existing supply and transportation and storage arrangements that are not replaced with contracts with similar terms and pricing;
- our ability to complete necessary or desirable expansion or infrastructure development projects, which may delay or prevent us from serving our customers or expanding our business;
- operational and mechanical hazards or interruptions;
- adverse labor relations;
- the effectiveness of our strategies to reduce earnings lag, revenue protection strategies and risk mitigation strategies, which may be affected by risks beyond our control such as commodity price volatility, counterparty performance or creditworthiness and interest rate risk;
- the capital-intensive nature of our business, and the availability of and access to, in general, funds to meet our debt obligations prior to or when they become due and to fund our operations and capital expenditures, either through (i) cash on hand, (ii) operating cash flow, or (iii) access to the capital markets and other sources of liquidity;
- our ability to obtain capital on commercially reasonable terms, or on terms acceptable to us, or at all;
- limitations on our operating flexibility, earnings and cash flows due to restrictions in our financing arrangements;
- cross-default provisions in our borrowing arrangements, which may lead to our inability to satisfy all of our outstanding obligations in the event of a default on our part;
- changes in the financial markets during the periods covered by the forward-looking statements, particularly those affecting the availability of capital and our ability to refinance existing debt and fund investments and acquisitions to execute our business strategy;
- actions of rating agencies, including the ratings of debt, general corporate ratings and changes in the rating agencies' ratings criteria;
- changes in inflation and interest rates;
- our ability to recover the costs of natural gas purchased for our customers, including those related to Winter Storm Uri and any related financing required to support our purchase of natural gas supply, including the securitized financing currently contemplated in Texas;
- impact of potential impairment charges;
- volatility and changes in markets for natural gas and our ability to secure additional and sufficient liquidity on reasonable commercial terms to cover costs associated with such volatility;
- possible loss of LDC franchises or other adverse effects caused by the actions of municipalities;
- payment and performance by counterparties and customers as contracted and when due, including our counterparties maintaining ordinary course terms of supply and payments;
- changes in existing or the addition of new environmental, safety, tax and other laws to which we and our subsidiaries are subject, including those that may require significant expenditures, significant increases in operating costs or, in the case of noncompliance, substantial fines or penalties;
- the effectiveness of our risk-management policies and procedures, and employees violating our risk-management policies;
- the uncertainty of estimates, including accruals and costs of environmental remediation;
- advances in technology, including technologies that increase efficiency or that improve electricity's competitive position relative to natural gas;

- population growth rates and changes in the demographic patterns of the markets we serve, and economic conditions in these areas' housing markets;
- acts of nature and the potential effects of threatened or actual terrorism and war, including recent events in Europe;
- the sufficiency of insurance coverage to cover losses;
- the effects of our strategies to reduce tax payments;
- the effects of litigation and regulatory investigations, proceedings, including our rate cases, or inquiries and the requirements of our regulators as a result of the Tax Cuts and Jobs Act of 2017;
- changes in accounting standards;
- changes in corporate governance standards;
- existence of material weaknesses in our internal controls;
- our ability to comply with all covenants in our indentures and the ONE Gas Credit Agreement, a violation of which, if not cured in a timely manner, could trigger a default of our obligations;
- our ability to attract and retain talented employees, management and directors, and shortage of skilled-labor;
- unexpected increases in the costs of providing health care benefits, along with pension and postemployment health care benefits, as well as declines in the discount rates on, declines in the market value of the debt and equity securities of, and increases in funding requirements for, our defined benefit plans; and
- our ability to successfully complete merger, acquisition or divestiture plans, regulatory or other limitations imposed as a result of a merger, acquisition or divestiture, and the success of the business following a merger, acquisition or divestiture.

These factors are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of our forward-looking statements. Other factors could also have material adverse effects on our future results. These and other risks are described in greater detail in Part 1, Item 1A, Risk Factors, in this Annual Report. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. Other than as required under securities laws, we undertake no obligation to update publicly any forward-looking statement whether as a result of new information, subsequent events or change in circumstances, expectations or otherwise.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our exposure to market risk discussed below includes forward-looking statements. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur since actual gains and losses will differ from those estimated based on actual fluctuations in commodity prices or interest rates and the timing of transactions.

Commodity Price Risk

Our commodity price risk, driven primarily by fluctuations in the price of natural gas, is mitigated by our purchased-gas cost adjustment mechanisms through which we pass-through natural gas costs to our customers without profit. We may use derivative instruments to hedge the cost of a portion of our anticipated natural gas purchases during the winter heating months to reduce the impact on our customers of upward market price volatility of natural gas. Additionally, we inject natural gas into storage during the summer months, when natural gas prices are typically lower, and withdraw the natural gas during the winter heating season. Gains or losses associated with these derivative instruments and storage activities are included in, and recoverable through our purchased-gas cost adjustment mechanisms, which are subject to review by regulatory authorities.

Interest-Rate Risk

We are exposed to interest-rate risk primarily associated with commercial paper borrowings, borrowings under our credit agreement, and new debt financing needed to fund capital requirements, including future contractual obligations and maturities of long-term and short-term debt. We may manage interest-rate risk on future borrowings through the use of fixed-rate debt, floating-rate debt and, at times, interest-rate swaps. Fixed-rate swaps may be used to reduce our risk of increased interest costs during periods of rising interest rates. Floating-rate swaps may be used to convert the fixed rates of long-term borrowings into short-term variable rates.

Counterparty Credit Risk

We assess the creditworthiness of our customers. Those customers who do not meet minimum standards are required to provide security, including deposits or other forms of collateral, when appropriate and allowed by tariff. With approximately 2.3 million customers across three states, we are not exposed materially to a concentration of credit risk. We maintain a provision for doubtful accounts based upon factors surrounding the credit risk of customers, historical trends, consideration of the current credit environment and other information. We are able to recover the fuel-related portion of bad debts through our purchased-gas cost adjustment mechanisms.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of ONE Gas, Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of ONE Gas, Inc. and its subsidiaries (the "Company") as of December 31, 2022 and 2021, and the related consolidated statements of income, of comprehensive income, of equity and of cash flows for each of the three years in the period ended December 31, 2022, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for the Effects of Regulatory Matters

As described in Notes 1 and 10 to the consolidated financial statements, the Company is subject to rate regulation and accounting requirements of regulatory authorities in the states in which it operates, and it follows the accounting and reporting guidance for regulated operations, including evaluating regulatory decisions to determine appropriate revenue recognition, cost deferrals, recoverability for regulatory assets and refund requirements for regulatory liabilities. As disclosed by management, regulatory assets are recorded for costs that have been deferred for which future recovery through customer rates is considered probable and regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. As a result, certain costs that would normally be expensed under accounting principles generally accepted in the United States of America for non-regulated entities are capitalized or deferred on the balance sheet because it is probable they can be recovered through rates. The amounts to be recovered or recognized are based upon historical experience and management’s understanding of regulations and may be affected by decisions of the regulatory authorities or the issuance of new regulations. Should recovery cease due to regulatory actions, certain regulatory assets may no longer meet the criteria for recognition, and accordingly, the Company may be required to write off the regulatory assets at that time. As described in Note 10, in August 2022, the proceeds received related to the securitization of the costs related to the winter weather event reflected the recovery of the related regulatory asset. As of December 31, 2022, there were $606 million of deferred costs included in regulatory assets and $577 million of regulatory liabilities awaiting cash outflow or potential refund.

The principal considerations for our determination that performing procedures relating to the Company’s accounting for the effects of regulatory matters is a critical audit matter are (i) the significant judgment by management in evaluating the impact of regulatory orders and accounting guidance on relevant transactions and (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence related to management’s evaluation of revenue recognition, cost deferrals, and recoverability of regulatory assets, including the securitization of the costs related to the winter weather event and the recovery of the related regulatory assets, and refund requirements for regulatory liabilities.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to the impact of regulatory orders and accounting guidance on relevant transactions, including controls over management’s process for evaluating and recording (i) deferred costs, including the amounts to be deferred and the future recovery, resulting in regulatory assets or (ii) a reduction to revenues for amounts that will be credited to customers, resulting in regulatory liabilities. These procedures also included, among others, (i) evaluating management’s process for identifying relevant transactions which require application of regulatory accounting guidance; (ii) evaluating the reasonableness of management’s assessment regarding revenue recognition, probability of recovery and establishment of regulatory assets, including the securitization of the costs related to the winter weather event and the recovery of the related regulatory assets, and the establishment of regulatory liabilities; and (iii) testing the regulatory assets and regulatory liabilities considering the provisions and formulas outlined in rate orders and other regulatory correspondence.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
February 23, 2023

We have served as the Company’s auditor since 2013.

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ONE Gas, Inc.
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31, 2022	2021	2020
	(*Thousands of dollars, except per share amounts*)		
Total revenues	**$ 2,578,005**	$ 1,808,597	$ 1,530,268
Cost of natural gas	**1,459,087**	775,006	537,445
Operating expenses			
Operations and maintenance	**472,265**	449,676	431,115
Depreciation and amortization	**228,479**	207,233	194,881
General taxes	**68,217**	66,424	63,311
Total operating expenses	**768,961**	723,333	689,307
Operating income	**349,957**	310,258	303,516
Other expense, net	**(4,183)**	(3,207)	(3,020)
Interest expense, net	**(77,506)**	(60,301)	(62,505)
Income before income taxes	**268,268**	246,750	237,991
Income taxes	**(46,526)**	(40,316)	(41,579)
Net income	**$ 221,742**	$ 206,434	$ 196,412
Earnings per share			
Basic	**$ 4.09**	$ 3.85	$ 3.70
Diluted	**$ 4.08**	$ 3.85	$ 3.68
Average shares (*thousands*)			
Basic	**54,207**	53,575	53,133
Diluted	**54,338**	53,674	53,370
Dividends declared per share of stock	**$ 2.48**	$ 2.32	$ 2.16

See accompanying Notes to Consolidated Financial Statements.

ONE Gas, Inc.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2022	**2021**	**2020**
		(*Thousands of dollars*)	
Net income	**$ 221,742**	$ 206,434	$ 196,412
Other comprehensive income (loss), net of tax			
Change in pension and other postemployment benefit plans liability, net of tax of $(1,705), $(379), and $289, respectively	**5,823**	1,250	(1,038)
Total other comprehensive income (loss), net of tax	**5,823**	1,250	(1,038)
Comprehensive income	**$ 227,565**	$ 207,684	$ 195,374

See accompanying Notes to Consolidated Financial Statements.

ONE Gas, Inc.
CONSOLIDATED BALANCE SHEETS

	December 31, 2022	December 31, 2021
Assets	(*Thousands of dollars*)	
Property, plant and equipment		
Property, plant and equipment	**$ 7,834,557**	$ 7,274,268
Accumulated depreciation and amortization	**2,205,717**	2,083,433
Net property, plant and equipment	**5,628,840**	5,190,835
Current assets		
Cash and cash equivalents	**9,681**	8,852
Restricted cash and cash equivalents	**8,446**	—
Total cash, cash equivalents and restricted cash and cash equivalents	**18,127**	8,852
Accounts receivable, net	**553,834**	341,756
Materials and supplies	**70,873**	54,892
Natural gas in storage	**269,205**	179,646
Regulatory assets	**275,572**	1,611,676
Other current assets	**29,997**	27,742
Total current assets	**1,217,608**	2,224,564
Goodwill and other assets		
Regulatory assets	**330,831**	724,862
Securitized intangible asset, net	**323,838**	—
Goodwill	**157,953**	157,953
Other assets	**117,326**	103,906
Total goodwill and other assets	**929,948**	986,721
Total assets	**$ 7,776,396**	$ 8,402,120

See accompanying Notes to Consolidated Financial Statements.

ONE Gas, Inc.
CONSOLIDATED BALANCE SHEETS
(Continued)

	December 31, 2022	December 31, 2021
Equity and Liabilities	(*Thousands of dollars*)	
Equity and long-term debt		
Common stock, $0.01 par value: authorized 250,000,000 shares; issued and outstanding 55,349,954 shares at December 31, 2022; issued and outstanding 53,633,210 shares at December 31, 2021	**$ 553**	$ 536
Paid-in capital	**1,932,714**	1,790,362
Retained earnings	**651,863**	565,161
Accumulated other comprehensive loss	**(704)**	(6,527)
Total equity	**2,584,426**	2,349,532
Other long-term debt, excluding current maturities, net of issuance costs	**2,352,400**	3,683,378
Securitized utility tariff bonds, excluding current maturities, net of issuance costs	**309,343**	—
Total-long term debt, excluding current maturities, net of issuance costs	**2,661,743**	**3,683,378**
Total equity and long-term debt	**5,246,169**	6,032,910
Current liabilities		
Current maturities of securitized utility tariff bonds	**20,716**	—
Notes payable	**552,000**	494,000
Accounts payable	**360,493**	258,554
Accrued taxes other than income	**78,352**	67,035
Regulatory liabilities	**47,867**	8,090
Customer deposits	**57,854**	62,454
Other current liabilities	**72,137**	90,360
Total current liabilities	**1,189,419**	980,493
Deferred credits and other liabilities		
Deferred income taxes	**698,456**	695,284
Regulatory liabilities	**529,441**	552,928
Employee benefit obligations	**19,587**	35,226
Other deferred credits	**93,324**	105,279
Total deferred credits and other liabilities	**1,340,808**	1,388,717
Commitments and contingencies		
Total liabilities and equity	**$ 7,776,396**	$ 8,402,120

See accompanying Notes to Consolidated Financial Statements.

ONE Gas, Inc.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31, 2022	2021	2020
	(*Thousands of dollars*)		
Operating activities			
Net income	$ 221,742	$ 206,434	$ 196,412
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	228,479	207,233	194,881
Deferred income taxes	(22,034)	43,449	18,485
Share-based compensation expense	10,741	10,498	9,803
Provision for doubtful accounts	6,003	9,131	15,450
Proceeds from government securitization of winter weather event costs	1,330,582	—	—
Changes in assets and liabilities:			
Accounts receivable	(213,656)	(57,902)	(58,423)
Materials and supplies	(15,981)	(2,126)	2,966
Natural gas in storage	(89,559)	(85,700)	10,313
Asset removal costs	(47,032)	(49,029)	(40,833)
Accounts payable	85,915	107,207	28,376
Accrued taxes other than income	11,317	3,235	15,844
Customer deposits	(4,600)	(5,574)	10,041
Regulatory assets and liabilities - current	52,417	(1,562,574)	(38,773)
Regulatory assets and liabilities - noncurrent	53,992	(367,210)	23,648
Employee benefit obligation	—	—	(3,109)
Other assets and liabilities - current	(23,377)	18,461	(12,877)
Other assets and liabilities - noncurrent	(14,107)	(11,190)	(7,704)
Cash provided by (used in) operating activities	1,570,842	(1,535,657)	364,500
Investing activities			
Capital expenditures	(609,486)	(495,246)	(471,345)
Other investing expenditures	(8,632)	(7,554)	(2,804)
Other investing receipts	4,008	1,717	3,777
Cash used in investing activities	(614,110)	(501,083)	(470,372)
Financing activities			
Borrowings (repayment) on notes payable, net	58,000	75,775	(98,275)
Issuance of other long-term debt, net of discounts	297,591	2,498,895	298,428
Issuance of securitized utility tariff bonds, net of discounts	335,931	—	—
Long-term debt financing costs	(8,567)	(35,110)	(2,885)
Issuance of common stock	133,711	26,662	19,383
Repayment of other long-term debt	(1,627,000)	(400,000)	—
Dividends paid	(133,954)	(123,912)	(114,372)
Tax withholdings related to net share settlements of stock compensation	(3,169)	(4,711)	(6,267)
Cash provided by (used in) financing activities	(947,457)	2,037,599	96,012
Change in cash, cash equivalents, restricted cash and restricted cash equivalents	9,275	859	(9,860)
Cash, cash equivalents, restricted cash and restricted cash equivalents at beginning of period	8,852	7,993	17,853
Cash, cash equivalents, restricted cash and restricted cash equivalents at end of period	$ 18,127	$ 8,852	$ 7,993
Supplemental cash flow information:			
Cash paid for interest, net of amounts capitalized	$ 84,871	$ 70,066	$ 60,126
Cash paid (received) for income taxes, net	$ 67,421	$ (10,809)	$ 30,361

See accompanying Notes to Consolidated Financial Statements.

ONE Gas, Inc.
CONSOLIDATED STATEMENTS OF EQUITY

	Common Stock Issued	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total Equity
	(Shares)			*(Thousands of dollars)*		
January 1, 2020	52,771,749	$ 528	$ 1,733,092	$ 402,509	$ (6,739)	$ 2,129,390
Net income	—	—	—	196,412	—	196,412
Other comprehensive loss	—	—	—	—	(1,038)	(1,038)
Common stock issued and other	394,984	4	22,915	—	—	22,919
Common stock dividends - $2.16 per share	—	—	914	(115,286)	—	(114,372)
December 31, 2020	53,166,733	532	1,756,921	483,635	(7,777)	2,233,311
Net income	—	—	—	206,434	—	206,434
Other comprehensive income	—	—	—	—	1,250	1,250
Common stock issued and other	466,477	4	32,445	—	—	32,449
Common stock dividends - $2.32 per share	—	—	996	(124,908)	—	(123,912)
December 31, 2021	53,633,210	536	1,790,362	565,161	(6,527)	2,349,532
Net income	**—**	**—**	**—**	**221,742**	**—**	**221,742**
Other comprehensive income	**—**	**—**	**—**	**—**	**5,823**	**5,823**
Common stock issued and other	**1,716,744**	**17**	**141,266**	—	—	**141,283**
Common stock dividends - $2.48 per share	**—**	**—**	**1,086**	**(135,040)**	—	**(133,954)**
December 31, 2022	**55,349,954**	**$ 553**	**$ 1,932,714**	**$ 651,863**	**$ (704)**	**$ 2,584,426**

See accompanying Notes to Consolidated Financial Statements.

ONE Gas, Inc.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Nature of Operations - We provide natural gas distribution services to approximately 2.3 million customers in Oklahoma, Kansas and Texas through our three divisions, Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service, respectively. We primarily serve residential, commercial and transportation customers in all three states. We are a corporation incorporated under the laws of the state of Oklahoma, and our common stock is listed on the NYSE under the trading symbol “OGS.”

Basis of Presentation - The consolidated financial statements include the accounts of our natural gas distribution business as set forth in “Organization and Nature of Operations” above. All significant balances and transactions between our subsidiaries have been eliminated.

Use of Estimates - The preparation of our consolidated financial statements and related disclosures in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions that cannot be known with certainty that affect the reported amount of assets and liabilities, and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. These estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Items that may be estimated include, but are not limited to, the economic useful life of assets, fair value of assets and liabilities, provisions for doubtful accounts receivable, unbilled revenues for natural gas delivered but for which meters have not been read, natural gas purchased but for which no invoice has been received, provision for income taxes, including any deferred income tax valuation allowances, the results of litigation and various other recorded or disclosed amounts.

We evaluate these estimates on an ongoing basis using historical experience and other methods we consider reasonable based on the particular circumstances. Nevertheless, actual results may differ significantly from the estimates. Any effects on our financial position or results of operations from revisions to these estimates are recorded in the period when the facts that give rise to the revision become known.

Revenues - We recognize revenue from contracts with customers to depict the transfers of goods and services to customers at an amount that we expect to be entitled to receive in exchange for these goods and services. Our sources of revenue are disaggregated by natural gas sales, transportation revenues, and miscellaneous revenues, which are primarily one-time service fees, that meet the requirements of ASC 606. Certain revenues that do not meet the requirements of ASC 606 are classified as other revenues in our Notes to Consolidated Financial Statements in this Annual Report.

Our natural gas sales to customers and transportation revenues represent revenues from contracts with customers through implied contracts established by our tariffs approved by regulatory authorities. Our customers receive the benefits of our performance when the commodity is delivered to the customer. The performance obligation is satisfied over time as the customer receives the natural gas.

For deliveries of natural gas, we read meters and bill customers on a monthly cycle. We recognize revenues upon the delivery of natural gas or services rendered to customers. The billing cycles for customers do not necessarily coincide with the accounting periods used for financial reporting purposes. We accrue unbilled revenues for natural gas that has been delivered but not yet billed at the end of an accounting period. We use the invoice method practical expedient, where we recognize revenue for volumes delivered for which we have a right to invoice. Our estimate of accrued unbilled revenue is based on a percentage estimate of amounts unbilled each month, which is dependent upon a number of factors, some of which require management’s judgment. These factors include customer consumption patterns and the impact of weather on usage. The accrued unbilled natural gas sales revenue at December 31, 2022 and 2021 was $269.5 million and $183.2 million, respectively, and is included in accounts receivable on our consolidated balance sheets.

Our miscellaneous revenues from contracts with customers represent implied contracts established by our tariff rates approved by the regulatory authorities and include miscellaneous utility services with the performance obligation satisfied at a point in time when services are rendered to the customer.

Total other revenues consist of revenues associated with regulatory mechanisms that do not meet the requirements of ASC 606 as revenue from contracts with customers, but authorize us to accrue revenues earned based on tariffs approved by regulatory authorities. Other revenues - natural gas sales primarily relate to the WNA mechanism in Kansas. This mechanism adjusts our revenues earned for the variance between actual and normal HDDs. This mechanism can have either positive (warmer than normal) or negative (colder than normal) effects on revenues.

We collect and remit other taxes on behalf of governmental authorities, and we record these amounts in accrued taxes other than income in our consolidated balance sheets. See Note 2 for additional discussion of revenues.

Cost of Natural Gas - Cost of natural gas includes commodity purchases, fuel, storage, transportation and other gas purchase costs recovered through our cost of natural gas regulatory mechanisms and does not include an allocation of general operating costs or depreciation and amortization. These cost of natural gas regulatory mechanisms provide a method of recovering natural gas costs on an ongoing basis without a profit. See Note 10 for additional discussion of purchased gas cost recoveries.

Cash, Cash Equivalents and Restricted Cash and Cash Equivalents - Cash and cash equivalents consist of highly liquid investments, which are readily convertible into cash and have original maturities of three months or less. Restricted cash consists of funds that are contractually or legally restricted as to usage or withdrawal and have been presented separately from cash and cash equivalents on our consolidated balance sheets. Restricted cash and cash equivalents accounts were established for payment of Securitized Utility Tariff Bond issuance costs and payment of debt service on those bonds.

Accounts Receivable - Accounts receivable represent valid claims against nonaffiliated customers for natural gas sold or services rendered, net of an allowance for doubtful accounts. We assess the creditworthiness of our customers. Those customers who do not meet minimum standards may be required to provide security, including deposits and other forms of collateral, when appropriate and allowed by our tariffs. With approximately 2.3 million customers across three states, we are not exposed materially to a concentration of credit risk. We maintain an allowance for doubtful accounts based upon factors surrounding the credit risk of customers, historical trends, consideration of the current credit environment and other information. We are able to recover natural gas costs related to uncollectible accounts through purchased-gas cost adjustment mechanisms. At December 31, 2022 and 2021, our allowance for doubtful accounts was $16.7 million and $18.7 million, respectively.

Inventories - Natural gas in storage is accounted for on the basis of weighted-average cost. Materials and supplies inventories are stated at the lower of weighted-average cost or net realizable value.

Leases - We determine if an arrangement is a lease at inception if the contract conveys the right to control the use and obtain substantially all the economic benefits from the use of an identified asset for a period of time in exchange for consideration. We identify a lease as a finance lease if the agreement includes any of the following criteria: transfer of ownership by the end of the lease term; an option to purchase the underlying asset that the lessee is reasonably certain to exercise; a lease term that represents 75 percent or more of the remaining economic life of the underlying asset; a present value of lease payments and any residual value guaranteed by the lessee that equals or exceeds 90 percent of the fair value of the underlying asset; or an underlying asset that is so specialized in nature that there is no expected alternative use to the lessor at the end of the lease term. A lease that does not meet any of these criteria is considered an operating lease.

Lease right-of-use assets represent our right to use an underlying asset for the lease term and lease liabilities represent our obligation to make lease payments arising from the lease. Right-of-use assets and liabilities are recognized at the commencement date of a lease based on the present value of lease payments over the lease term. Our lease terms may include options to extend or terminate the lease. We include these extension or termination options in the determination of the lease term when it is reasonably certain that we will exercise that option. We have lease agreements with lease and non-lease components, which are accounted for separately. Additionally, for certain office equipment leases, we apply a portfolio approach to effectively account for the operating lease right-of-use assets and liabilities. We do not recognize leases having a term of less than one year in our consolidated balance sheets.

For purposes of determining the present value of the lease payments, we use a lease's implicit interest rate when readily determinable. As most of our leases do not provide an implicit interest rate, we use an incremental borrowing rate based on available information at the commencement of the lease. Lease cost for operating leases is recognized on a straight-line basis over the lease term. See Note 5 for additional information regarding our leases.

Derivatives and Risk Management Activities - We record all derivative instruments at fair value, with the exception of normal purchases and normal sales that are expected to result in physical delivery. The accounting for changes in the fair value of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and, if so, the reason for holding it, or if regulatory requirements impose a different accounting treatment.

If certain conditions are met, we may elect to designate a derivative instrument as a hedge of exposure to changes in fair values or cash flows. We have not elected to designate any of our derivative instruments as hedges.

The table below summarizes the various ways in which we account for our derivative instruments and the impact on our consolidated financial statements:

	Recognition and Measurement	
Accounting Treatment	**Balance Sheet**	**Income Statement**
Normal purchases and normal sales	- Fair value not recorded	- Change in fair value not recognized in earnings
Mark-to-market	- Recorded at fair value	- Change in fair value recognized in, and recoverable through, the purchased-gas cost adjustment mechanisms

See Note 9 for additional information regarding our economic hedging activities using derivatives.

Fair Value Measurements - We define fair value as the price that would be received from the sale of an asset or the transfer of a liability in an orderly transaction between market participants at the measurement date. We use the market and income approaches to determine the fair value of our assets and liabilities and consider the markets in which the transactions are executed. We measure the fair value of a group of financial assets and liabilities consistent with how a market participant would price the net risk exposure at the measurement date.

Fair Value Hierarchy - At each balance sheet date, we utilize a fair value hierarchy to classify fair value amounts recognized or disclosed in our consolidated financial statements based on the observability of inputs used to estimate such fair value. The levels of the hierarchy are described below:

- Level 1 - Unadjusted quoted prices in active markets for identical assets or liabilities;
- Level 2 - Significant observable pricing inputs other than quoted prices included within Level 1 that are, either directly or indirectly, observable as of the reporting date. Essentially, this represents inputs that are derived principally from or corroborated by observable market data; and
- Level 3 - May include one or more unobservable inputs that are significant in establishing a fair value estimate. These unobservable inputs are developed based on the best information available and may include our own internal data.

We recognize transfers into and out of the levels as of the end of each reporting period.

Determining the appropriate classification of our fair value measurements within the fair value hierarchy requires management's judgment regarding the degree to which market data is observable or corroborated by observable market data. We categorize derivatives for which fair value is determined using multiple inputs within a single level, based on the lowest level input that is significant to the fair value measurement in its entirety. See Note 9 for additional information regarding our fair value measurements.

Property, Plant and Equipment - Our properties are stated at cost, which includes direct construction costs such as direct labor, materials, burden and AFUDC. Generally, the cost of our property retired or sold, plus removal costs, less salvage, is charged to accumulated depreciation. Gains and losses from sales or retirement of an entire operating unit or system of our properties are recognized in income. Maintenance and repairs are charged directly to expense.

AFUDC represents the cost of borrowed funds used to finance construction activities. We capitalize interest costs during the construction or upgrade of qualifying assets. Capitalized interest is recorded as a reduction to interest expense.

Our properties are depreciated using the straight-line method over their estimated useful lives. Generally, we apply composite depreciation rates to functional groups of property having similar economic circumstances. We periodically conduct depreciation studies to assess the economic lives of our assets. These depreciation studies are completed as a part of our regulatory proceedings, and the changes in economic lives, if applicable, are implemented prospectively when the new rates are approved by our regulators and become effective. Changes in the estimated economic lives of our property, plant and equipment could have a material effect on our financial position, results of operations or cash flows.

Property, plant and equipment on our consolidated balance sheets includes construction work in process for capital projects that have not yet been placed in service and therefore are not being depreciated. Assets are transferred out of construction work in process when they are substantially complete and ready for their intended use.

See Note 12 for additional information regarding our property, plant and equipment.

Impairment of Goodwill and Long-Lived Assets - We assess our goodwill for impairment at least annually as of July 1, unless events or a change in circumstances indicate an impairment may have occurred before that time. As part of our goodwill impairment test, we first assess qualitative factors (including macroeconomic conditions, industry and market considerations, cost factors and overall financial performance) to determine whether it is more likely than not that our fair value is less than the carrying amount of our net assets. If further testing is necessary or a quantitative test is elected to refresh our recurring qualitative assessment, we perform a quantitative impairment test for goodwill.

Our impairment assessment is performed by comparing our fair value with our book value, including goodwill. If the fair value is less than the book value, an impairment is measured by the amount of our carrying value that exceeds fair value, not to exceed the carrying amount of our goodwill.

To estimate fair value, we use two generally accepted valuation approaches, an income approach and a market approach, using assumptions consistent with a market participant's perspective. Under the income approach, we use anticipated cash flows over a period of years plus a terminal value and discount these amounts to their present value using appropriate discount rates. Under the market approach, we apply acquisition multiples to forecasted cash flows. The acquisition multiples used are consistent with historical market transactions. The forecasted cash flows are based on average forecasted cash flows over a period of years.

Our goodwill impairment analysis performed in 2022 and 2021 utilized a qualitative assessment and did not result in any impairment indicators, nor did our analysis reflect our reporting unit at risk. Subsequent to July 1, 2022, no event has occurred indicating that it is more likely than not that our fair value is less than the carrying value of our net assets.

We assess our long-lived assets for impairment whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. An impairment is indicated if the carrying amount of a long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset. We determined that there were no material asset impairments in 2022, 2021 or 2020.

Securitized Intangible Asset - On November 18, 2022, KGSS-I acquired the Securitized Utility Tariff Property from Kansas Gas Service for $327.4 million. The Securitized Utility Tariff Property is classified as a securitized intangible asset on our consolidated balance sheets. This securitized intangible asset will be amortized over 10 years, the estimated period needed to collect the required amounts from Kansas Gas Service's customers to service the Securitized Utility Tariff Bonds. The amortization expense related to the securitized intangible asset will be included in depreciation and amortization expense in our consolidated statements of income. For the year ended December 31, 2022, we recorded $3.5 million of amortization expense related to the securitized intangible asset. At the end of its life, this securitized intangible asset will have no residual value. See Note 4 for additional information about the Securitized Utility Tariff Bonds and Notes 10 and 11 for additional information about the securitization transaction.

Finite-lived intangible assets are stated at cost, net of accumulated amortization, which is recorded on a straight-line or accelerated basis over the life of the asset. We review amortizable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value.

Regulation - We are subject to the rate regulation and accounting requirements of the OCC, KCC, RRC and various municipalities in Texas. We follow the accounting and reporting guidance for regulated operations, including evaluating regulatory decisions to determine appropriate revenue recognition, cost deferrals and recoverability for regulatory assets and refund requirements for regulatory liabilities. During the ratemaking process, regulatory authorities set the framework for what we can charge customers for our services and establish the manner that our costs are accounted for, including allowing us to defer recognition of certain costs and permitting recovery of the amounts through rates over time, as opposed to expensing such costs as incurred. Examples include weather normalization, unrecovered purchased-gas costs, extraordinary costs associated with Winter Storm Uri, pension and postemployment benefit costs and ad-valorem taxes. This allows us to stabilize rates over time rather than passing such costs on to the customer for immediate recovery. Actions by regulatory authorities could have an effect on the amount recovered from customers. Any difference in the amount recoverable and the amount deferred is recorded as income or expense at the time of the regulatory action. A write-off of regulatory assets and costs not recovered may be required if all or a portion of the regulated operations have rates that are no longer:

- established by independent regulators;
- designed to recover our costs of providing regulated services; and
- set at levels that will recover our costs when considering the demand and competition for our services.

Should recovery cease due to regulatory actions, certain of these assets may no longer meet the criteria for recognition and accordingly, a write-off of regulatory assets and stranded costs may be required. There were no write-offs of regulatory assets resulting from the failure to meet the criteria for capitalization during 2022, 2021 and 2020.

See Note 10 for additional information regarding our regulatory assets and liabilities.

Pension and Other Postemployment Employee Benefits - We have defined benefit pension plans covering eligible employees. We also sponsor welfare plans that provide other postemployment medical and life insurance benefits to eligible employees who retire with at least five years of service. To calculate the costs and liabilities related to our plans, we utilize an outside actuarial consultant, which uses statistical and other factors to anticipate future events. These factors include assumptions about the discount rate, expected return on plan assets, rate of future compensation increases, age and mortality and employment periods. We use tables issued by the Society of Actuaries to estimate mortality rates. In determining the projected benefit obligations and costs, assumptions can change from period to period and may result in material changes in the cost and liabilities we recognize.

Income Taxes - Deferred income taxes are recorded for the difference between the financial statement and income tax basis of assets and liabilities and carryforward items, based on income tax laws and rates existing at the time the temporary differences are expected to reverse. The effect on deferred income taxes of a change in tax rates is deferred and amortized for operations regulated by the OCC, KCC, RRC and various municipalities in Texas, if, as a result of an action by a regulator, it is probable that the effect of the change in tax rates will be recovered from or returned to customers through future rates. We continue to amortize previously deferred investment tax credits for ratemaking purposes over the periods prescribed by our regulators.

A valuation allowance for deferred income tax assets is recognized when it is more likely than not that some or all of the benefit from the deferred income tax asset will not be realized. To assess that likelihood, we use estimates and judgment regarding our future taxable income, as well as the jurisdiction in which such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include our current financial position, our results of operations, both actual and forecasted, the reversal of deferred income tax liabilities, as well as the current and forecasted business economics of our industry. We had no valuation allowance at December 31, 2022 and 2021.

We utilize a more-likely-than-not recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position that is taken or expected to be taken in a tax return. We reflect penalties and interest as part of income tax expense as they become applicable for tax provisions that do not meet the more-likely-than-not recognition threshold and measurement attribute. There were no material uncertain tax positions at December 31, 2022 and 2021.

Changes in tax laws or tax rates are recognized in the financial reporting period that includes the enactment date.

See Note 15 for additional information regarding income taxes.

Asset Retirement Obligations - Asset retirement obligations represent legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. Certain long-lived assets that comprise our natural gas distribution systems, primarily our pipeline assets, are subject to agreements or regulations that give rise to an asset retirement obligation for removal or other disposition costs associated with retiring the assets in place upon the discontinued use of the natural gas distribution system. We recognize the fair value of a liability for an asset retirement obligation in the period when it is incurred if a reasonable estimate of the fair value can be made. We are not able to estimate reasonably the fair value of the asset retirement obligations for portions of our assets because the settlement dates are indeterminable given our expected continued use of the assets with proper maintenance. We expect our natural gas distribution systems will continue in operation for the foreseeable future. Based on our proximity to significant natural gas reserves and infrastructure and the widespread use of natural gas for heating and cooking activities by residential and commercial customers in our service areas, we expect supply and demand to exist for the foreseeable future.

In accordance with long-standing regulatory treatment, we collect through rates the estimated costs of removal on certain regulated properties through depreciation expense as a portion of the net salvage value component of our composite deprecation rates, with a corresponding credit to accumulated depreciation and amortization. These removal costs collected through our rates include costs attributable to legal and nonlegal removal obligations. These costs are addressed prospectively in depreciation rates, rather than as a regulatory liability, in each general rate order.

For financial reporting purposes, if the removal costs collected have exceeded our removal costs incurred, we estimate a regulatory liability using current rates since the last general rate order in each of our jurisdictions. At December 31, 2022 and

2021, we have not recorded a regulatory liability, as our removal costs incurred have exceeded amounts collected through our depreciation rates. Significant uncertainty exists regarding the recording of these regulatory liabilities, pending, among other issues, clarification of regulatory intent. We continue to monitor the regulatory requirements, and any future regulatory liabilities incurred may be adjusted as more information is obtained. To the extent these estimated liabilities are adjusted, such amounts will be reclassified between accumulated depreciation and amortization and regulatory liabilities on our balance sheet and therefore will not have an impact on earnings.

Contingencies - Our accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be estimated reasonably. We expense legal fees as incurred and base our legal liability estimates on currently available facts and our estimates of the ultimate outcome or resolution. Accruals for the estimated cost of environmental remediation obligations generally are recognized no later than the completion of a remediation feasibility study. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings.

See Note 17 for additional information regarding contingencies.

Share-Based Payments - We expense the fair value of share-based payments net of estimated forfeitures. We estimate forfeiture rates based on historical forfeitures under our share-based payment plans.

Earnings per share - Basic EPS is calculated by dividing net income by the daily weighted-average number of common shares outstanding during the periods presented. Also, this calculation includes fully vested stock awards that have not yet been issued as common stock. Diluted EPS includes the above, plus unvested stock awards granted under our compensation plans and equity forward sale agreements, but only to the extent these instruments dilute earnings per share.

Segments - We operate in one reportable business segment: regulated public utilities that deliver natural gas primarily to residential, commercial and transportation customers. We define reportable business segments as components of an organization for which discrete financial information is available and operating results are evaluated on a regular basis by the chief operating decision maker (“CODM”) in order to assess performance and allocate resources. Our CODM is our Chief Executive Officer. Characteristics of our organization that were relied upon in making this determination include the similar nature of services we provide, the functional alignment of our organizational structure, and the reports that are regularly reviewed by the CODM for the purpose of assessing performance and allocating resources. Our management is functionally aligned and centralized, with performance evaluated based upon results of the entire distribution business. Capital allocation decisions are driven by asset integrity management, operating efficiency, growth opportunities and government-requested pipeline relocations, not geographic location or regulatory jurisdiction.

In 2022, 2021 and 2020, we had no single external customer from which we received 10 percent or more of our gross revenues.

Recently Issued Accounting Standards Update - In November 2021, the FASB issued ASU 2021-10, “Government Assistance (Topic 832): Disclosures by Business Entities about Government Assistance,” which will require disclosure about government assistance in the notes to the financial statements. The amendment requires annual disclosures about transactions with a government that are accounted for by applying a grant or contribution accounting model by analogy, including information about the nature of the transactions and the related accounting policy used to account for the transactions, the line items on the balance sheet and income statement that are affected by the transactions and the significant terms and conditions of the transactions, including commitments and contingencies. The amendment became effective for us beginning January 1, 2022. As the guidance is related only to disclosures in the notes to the financial statements, we do not anticipate any impact on our financial position, results of operations or cash flows. See Note 10 for additional discussion regarding our securitization transaction with the Oklahoma government that is accounted for by applying a grant accounting model by analogy.

In March 2020, the FASB issued ASU 2020-04, “Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting,” which provides relief from the accounting analysis and impacts that may otherwise be required for modifications to agreements (e.g., loans, debt securities, derivatives, borrowings) necessitated by reference rate reform. It also provides optional expedients to enable companies to continue to apply hedge accounting to certain hedging relationships impacted by reference rate reform. In the first quarter 2020, we adopted this new guidance effective for contracts modified between March 12, 2020 and December 31, 2022. In March 2022, we amended the ONE Gas Credit Agreement to change the defined benchmark rate to SOFR from LIBOR. Our adoption and subsequent amendment of the ONE Gas Credit Agreement did not result in a material impact to our consolidated financial statements.

2. REVENUE

The following table sets forth our revenues disaggregated by source for the periods indicated:

	Year Ended December 31, 2022	2021	2020
	(Thousands of dollars)		
Natural gas sales to customers	**$ 2,410,048**	$ 1,652,566	$ 1,381,141
Transportation revenues	**125,951**	118,492	113,855
Securitization customer charges (Note 11)	**5,769**	—	—
Miscellaneous revenues	**19,850**	16,757	15,505
Total revenues from contracts with customers	**2,561,618**	1,787,815	1,510,501
Other revenues - natural gas sales related	**3,403**	9,650	8,299
Other revenues	**12,984**	11,132	11,468
Total other revenues	**16,387**	20,782	19,767
Total revenues	**$ 2,578,005**	$ 1,808,597	$ 1,530,268

3. CREDIT FACILITY AND SHORT-TERM DEBT

On March 16, 2022, we entered into the first amendment to the second amended and restated ONE Gas Credit Agreement, which was previously amended and restated on March 16, 2021. The amendment extends the maturity date of the ONE Gas Credit Agreement to March 16, 2027, from March 16, 2026, and amends the ONE Gas Credit Agreement to provide that we may extend the maturity date, subject to the lenders' consent, by one year two additional times. The amendment also changed the benchmark rate defined in the ONE Gas Credit Agreement to SOFR. All other material terms and conditions of the ONE Gas Credit Agreement remain in full force and effect.

The ONE Gas Credit Agreement provides for a $1.0 billion revolving unsecured credit facility and includes a $20 million letter of credit subfacility and a $60 million swingline subfacility. We can request an increase in commitments of up to an additional $500 million upon satisfaction of customary conditions, including receipt of commitments from either new lenders or increased commitments from existing lenders. The ONE Gas Credit Agreement is available to provide liquidity for working capital, capital expenditures, acquisitions and mergers, the issuance of letters of credit and for other general corporate purposes.

The ONE Gas Credit Agreement contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining ONE Gas' total debt-to-capital ratio of no more than 70 percent at the end of any calendar quarter. At December 31, 2022, our total debt-to-capital ratio was 56 percent and we were in compliance with all covenants under the ONE Gas Credit Agreement. We may reduce the unutilized portion of the ONE Gas Credit Agreement in whole or in part without premium or penalty. The ONE Gas Credit Agreement contains customary events of default. Upon the occurrence of certain events of default, the obligations under the ONE Gas Credit Agreement may be accelerated and the commitments may be terminated.

At December 31, 2022, we had $1.2 million in letters of credit issued and no borrowings under the ONE Gas Credit Agreement, with $998.8 million of remaining credit available to repay our commercial paper borrowings.

In June 2021, we increased the size of our commercial paper program to permit the issuance of commercial paper to fund short-term borrowing needs in an aggregate principal amount not to exceed $1.0 billion outstanding at any time. Prior to this increase, our commercial paper program permitted us to issue commercial paper in an aggregate principal amount not to exceed $700 million outstanding at any time. The maturities of the commercial paper notes may vary, but may not exceed 270 days from the date of issue. Commercial paper is generally sold at par less a discount representing an interest factor. At December 31, 2022 and 2021, we had $552.0 million and $494.0 million of commercial paper outstanding, respectively. The weighted-average interest rate on our commercial paper was 4.75 percent and 0.38 percent at December 31, 2022 and 2021, respectively.

In connection with the second amendment and restatement of the ONE Gas Credit Agreement on March 16, 2021, all commitments under the ONE Gas 364-day Credit Agreement were terminated and all obligations under the ONE Gas 364-day Credit Agreement were discharged.

4. LONG-TERM DEBT

The table below presents a summary of our long-term debt outstanding for the periods indicated:

	Interest rate at December 31, 2022	December 31, 2022	December 31, 2021
		(*Thousands of dollars*)	
Senior unsecured notes:			
Senior unsecured notes due March 2023		$ —	$ 1,000,000
Senior unsecured floating rate notes due March 2023		—	400,000
Senior unsecured notes due February 2024	**3.610%**	**300,000**	300,000
Senior unsecured notes due March 2024	**1.100%**	**473,000**	700,000
Senior unsecured notes due May 2030	**2.000%**	**300,000**	300,000
Senior unsecured notes due September 2032	**4.250%**	**300,000**	—
Senior unsecured notes due February 2044	**4.658%**	**600,000**	600,000
Senior unsecured notes due November 2048	**4.500%**	**400,000**	400,000
Total senior unsecured notes		**2,373,000**	3,700,000
KGSS-I Securitized Utility Tariff Bonds	**5.486%**	**336,000**	—
Other	**8.000%**	**1,250**	1,261
Unamortized discounts on long-term debt		**(7,636)**	(5,454)
Debt issuance costs		**(20,143)**	(12,418)
Total long-term debt, net		**2,682,471**	3,683,389
Less: current maturities of securitized utility tariff bonds		**20,716**	—
Less: current maturities of long-term debt		**12**	11
Noncurrent portion of long-term debt, net		**$ 2,661,743**	$ 3,683,378

Senior Notes - In August 2022, we issued $300 million of 4.25 percent senior notes due September 2032. The proceeds from the issuance were used to repay amounts outstanding under our commercial paper program and for general corporate purposes.

In August 2022, we called $750 million of the $1.0 billion of 0.85 percent senior notes due March 2023, $150 million of the $700 million of 1.10 percent senior notes due March 2024 and the remaining $400 million of outstanding floating-rate senior notes due March 2023, using the proceeds received from the Oklahoma government in our securitization transaction for Oklahoma Natural Gas.

On November 18, 2022, KGSS-I issued $336 million of 5.486 percent Securitized Utility Tariff Bonds. The Securitized Utility Tariff Bonds have an interest rate of 5.486 percent and a term of 10 years with semi-annual principal repayments, which results in an expected weighted average life of the bonds of 5.5 years. The bonds are governed by an indenture between KGSS-I and the indenture trustee. The indenture contains certain covenants that restrict KGSS-I's ability to sell, transfer, convey, exchange, or otherwise dispose of its assets. See Note 10 for additional discussion of the securitization transactions.

In November 2022, we called the remaining $250 million of the $1.0 billion of 0.85 percent senior notes due March 2023 and $77 million of the $700 million of 1.10 percent senior notes due March 2024, using the proceeds from the securitization transaction for Kansas Gas Service.

In March 2021, we issued $1.0 billion of 0.85 percent senior notes due March 2023, $700 million of 1.10 percent senior notes due March 2024, and $800 million of floating-rate senior notes due March 2023. The net proceeds from the issuance were used for payment of gas purchases and related costs resulting from Winter Storm Uri and general corporate purposes.

In September 2021, we called $400 million of the floating-rate senior notes due March 2023 at par, using a combination of cash on hand and commercial paper. We did not have the right to call these senior notes prior to September 11, 2021.

The indenture governing our Senior Notes includes an event of default upon the acceleration of other indebtedness of $100 million or more. Such events of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of the outstanding Senior Notes to declare those Senior Notes immediately due and payable in full.

Depending on the series, we may redeem our Senior Notes at par, plus accrued and unpaid interest to the redemption date, starting three months or six months before their maturity dates. Prior to these dates, we may redeem these Senior Notes, in whole or in part, at a redemption price equal to the principal amount, plus accrued and unpaid interest and a make-whole premium. The redemption price will never be less than 100 percent of the principal amount of the respective Senior Note plus accrued and unpaid interest to the redemption date. Our Senior Notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness.

ONE Gas 2021 Term Loan Facility - On February 22, 2021, we entered into the ONE Gas 2021 Term Loan Facility as part of the financing of our natural gas purchases in order to provide sufficient liquidity to satisfy our obligations as a result of Winter Storm Uri. The net proceeds of the March 2021 debt issuance reduced the commitments under the ONE Gas 2021 Term Loan Facility on a dollar-for-dollar basis, and as a result no commitments remained outstanding and the facility was terminated concurrently with the closing of the debt issuance.

5. LEASES

We have operating leases for office facilities, gas storage facilities, IT equipment and right-of-way contracts. Our leases have remaining lease terms of one year to seven years, some of which include options to extend the leases for up to 10 years, and some of which include options to terminate the leases within specified time frames. We have not entered into any finance leases.

Our right-of-use asset is $23.3 million and $30.9 million as of December 31, 2022 and 2021, respectively, and is reported within other assets in our consolidated balance sheets. Operating lease liabilities are reported within our other current liabilities and other liabilities in our consolidated balance sheets. Total operating lease cost including immaterial amounts attributable to short-term operating leases was $7.8 million, $8.2 million, and $8.4 million in 2022, 2021 and 2020, respectively.

In 2022, we reassessed certain operating leases for office facilities and IT which were extended or modified, resulting in an decrease in our right-of-use asset and operating lease liability of $1.3 million and $1.3 million, respectively.

Other information related to operating leases		**Years Ended December 31,** 2022		2021		2020
				(Millions of dollars)		
Weighted-average remaining lease term		**5 years**		6 years		7 years
Weighted-average discount rate		**4.04 %**		2.78 %		2.81 %
Supplemental cash flows information						
Lease payments	**$**	**(8.2)**	$	(8.0)	$	(8.0)
Right-of-use assets obtained in exchange for lease obligations	**$**	**0.3**	$	0.4	$	9.8

Future minimum lease payments under non-cancellable operating leases		**December 31, 2022**
		(Millions of dollars)
2023	**$**	**6.5**
2024		**4.7**
2025		**4.0**
2026		**3.2**
2027		**3.0**
Thereafter		**4.3**
Total future minimum lease payments	**$**	**25.7**
Imputed interest		**(2.6)**
Total operating lease liability	**$**	**23.1**
Consolidated balance sheets as of December 31, 2022		
Current operating lease liability	**$**	**5.7**
Long-term operating lease liability		**17.4**
Total operating lease liability	**$**	**23.1**

6. EQUITY

Preferred Stock - At December 31, 2022, we had 50 million, $0.01 par value, authorized shares of preferred stock available. We have not issued or established any classes or series of shares of preferred stock.

Common Stock - At December 31, 2022, we had approximately 194.7 million shares of authorized common stock available for issuance.

At-the-Market Equity Program - In February 2020, we initiated an at-the-market equity program by entering into an equity distribution agreement under which we may issue and sell shares of our common stock with an aggregate offering price up to $250 million (including any shares of common stock that may be sold pursuant to the master forward sale confirmation entered into in connection with the equity distribution agreement and the related supplemental confirmations). Sales of common stock are made by means of ordinary brokers' transactions on the NYSE, in block transactions or as otherwise agreed to between us and the sales agent. We are under no obligation to offer and sell common stock under the program.

For the years ended December 31, 2022 and 2021, we sold and issued 403,792 and 281,124 shares of our common stock for $35.0 million and $21.4 million, respectively, generating proceeds, net of issuance costs, of $34.7 million and $21.1 million, respectively.

For the year ended December 31, 2022, we also executed forward sale agreements for 1,451,474 shares of our common stock. We did not enter into any forward sale agreements in 2021. On December 30, 2022, we settled forward sales agreements with respect to 1,162,071 shares of our common stock for net proceeds of $93.8 million. Had we settled the remaining 289,403 shares under the outstanding forward sale agreements as of December 31, 2022, we would have generated net proceeds of approximately $21.7 million.

At December 31, 2022, we had $63.1 million of equity available for issuance under the program.

Dividends Declared - For the years ended December 31, 2022 and 2021, we declared and paid dividends of $2.48 per share ($0.62 per share quarterly) and $2.32 per share ($0.58 per share quarterly), respectively. In January 2023, we declared a dividend of $0.65 per share ($2.60 per share on an annualized basis) for shareholders of record on February 24, 2023, payable on March 10, 2023.

7. ACCUMULATED OTHER COMPREHENSIVE LOSS

The following table sets forth the balance in accumulated other comprehensive loss for the periods indicated:

		Accumulated Other Comprehensive Income (Loss)
		(Thousands of dollars)
January 1, 2021	$	(7,777)
Pension and other postemployment benefit plans obligations		
Other comprehensive income before reclassification, net of tax of $11		78
Amounts reclassified from accumulated other comprehensive income (loss), net of tax of $(390)		1,172
Other comprehensive income		1,250
December 31, 2021		(6,527)
Pension and other postemployment benefit plans obligations		
Other comprehensive income before reclassification, net of tax of $(1,669)		**5,701**
Amounts reclassified from accumulated other comprehensive income (loss), net of tax of $(36)		**122**
Other comprehensive income		**5,823**
December 31, 2022	**$**	**(704)**

The following table sets forth the effect of reclassifications from accumulated other comprehensive loss on our consolidated statements of income for the periods indicated:

Details about Accumulated Other Comprehensive Income (Loss) Components	Years Ended December 31, 2022	2021	2020	Affected Line Item in the Consolidated Statements of Income
		(Thousands of dollars)		
Pension and other postemployment benefit plan obligations (a)				
Amortization of net loss	**$ 17,010**	$ 45,896	$ 42,492	
Amortization of unrecognized prior service cost (credit)	**289**	(279)	(117)	
	17,299	45,617	42,375	
Regulatory adjustments (b)	**(17,141)**	(44,055)	(41,183)	
	158	1,562	1,192	Income before income taxes
	(36)	(390)	(298)	Income tax expense
Total reclassifications for the period	**$ 122**	$ 1,172	$ 894	Net income

(a) These components of accumulated other comprehensive loss are included in the computation of net periodic benefit cost. See Note 14 for additional information regarding our net periodic benefit cost.
(b) Regulatory adjustments represent pension and other postemployment benefit costs expected to be recovered through rates and are deferred as part of our regulatory assets. See Note 10 for additional information regarding our regulatory assets and liabilities.

8. EARNINGS PER SHARE

Basic EPS is calculated by dividing net income by the daily weighted-average number of common shares outstanding during the periods presented, which includes fully vested stock awards that have not yet been issued as common stock. Diluted EPS is based on shares outstanding for the calculation of basic EPS, plus unvested stock awards granted under our compensation plans and equity forward sale agreements, but only to the extent these instruments dilute earnings per share.

The following tables set forth the computation of basic and diluted EPS from continuing operations for the periods indicated:

Year Ended December 31, 2022	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS Calculation			
Net income available for common stock	**$ 221,742**	**54,207**	**$ 4.09**
Diluted EPS Calculation			
Effect of dilutive securities	**—**	**131**	
Net income available for common stock and common stock equivalents	**$ 221,742**	**54,338**	**$ 4.08**

Year Ended December 31, 2021	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS Calculation			
Net income available for common stock	$ 206,434	53,575	$ 3.85
Diluted EPS Calculation			
Effect of dilutive securities	—	99	
Net income available for common stock and common stock equivalents	$ 206,434	53,674	$ 3.85

	Year Ended December 31, 2020		
	Income	Shares	Per Share Amount
	(*Thousands, except per share amounts*)		
Basic EPS Calculation			
Net income available for common stock	$ 196,412	53,133	$ 3.70
Diluted EPS Calculation			
Effect of dilutive securities	—	237	
Net income available for common stock and common stock equivalents	$ 196,412	53,370	$ 3.68

9. DERIVATIVE FINANCIAL INSTRUMENTS AND FAIR VALUE MEASUREMENTS

Derivative Instruments - At December 31, 2022, we held purchased natural gas call options for the heating season ending March 2023, with total notional amounts of 19.4 Bcf, for which we paid premiums of $14.1 million, and which had no fair value. At December 31, 2021, we held purchased natural gas call options for the heating season ended March 2022, with total notional amounts of 13.2 Bcf, for which we paid premiums of $9.5 million, and which had a fair value of $3.6 million. These contracts are included in, and recoverable through, our purchased-gas cost adjustment mechanisms. Additionally, premiums paid, changes in fair value and any settlements received associated with these contracts are deferred as part of our unrecovered purchased-gas costs in our consolidated balance sheets. Our natural gas call options are classified as Level 1, as fair value amounts are based on unadjusted quoted prices in active markets including settled prices on the New York Mercantile Exchange. There were no transfers between levels for the periods presented.

Other Financial Instruments - The approximate fair value of cash and cash equivalents, restricted cash and cash equivalents, accounts receivable and accounts payable is equal to book value, due to the short-term nature of these items. Our cash and cash equivalents and restricted cash and cash equivalents are comprised of cash and money market accounts, which we consider to be Level 1. At December 31, 2022, other current and noncurrent assets included $9.7 million of corporate bonds and $4.7 million of United States treasury notes, for which the fair value approximates our cost, and are classified as Level 2 and Level 1, respectively. At December 31, 2021, other current and noncurrent assets included $6.9 million of corporate bonds and $3.5 million of United States treasury notes, for which the fair value approximates our cost, and are classified as Level 2 and Level 1, respectively.

Short-term notes payable and commercial paper are due upon demand and, therefore, the carrying amounts approximate fair value and are classified as Level 1. The book value of our long-term debt, including current maturities, was $2.7 billion and $3.7 billion at December 31, 2022 and 2021, respectively. The estimated fair value of our long-term debt, including current maturities, was $2.5 billion and $3.9 billion at December 31, 2022 and 2021, respectively. The estimated fair value of our long-term debt was determined using quoted market prices, and is considered Level 2.

10. REGULATORY ASSETS AND LIABILITIES

The tables below present a summary of regulatory assets, net of amortization, and liabilities for the periods indicated:

	Remaining Recovery Period	December 31, 2022 Current	Noncurrent	Total
		(Thousands of dollars)		
Winter weather event costs	(a)	$ 221,926	$ 36,291	$ 258,217
Under-recovered purchased-gas costs	1 year	19,755	—	19,755
Pension and other postemployment benefit costs	See Note 14	—	258,257	258,257
Reacquired debt costs	6 years	812	3,347	4,159
MGP remediation costs	15 years	98	29,743	29,841
Ad-valorem tax	1 year	13,359	—	13,359
WNA	1 year	8,474	—	8,474
Customer credit deferrals	1 year	9,504	—	9,504
Other	1 to 18 years	1,644	3,193	4,837
Total regulatory assets, net of amortization		275,572	330,831	606,403
Pension and other postemployment benefit costs	See Note 14	(8,228)	—	(8,228)
Income tax rate changes	(a)	—	(529,441)	(529,441)
Over-recovered purchased-gas costs	1 year	(39,639)	—	(39,639)
Total regulatory liabilities		(47,867)	(529,441)	(577,308)
Net regulatory assets and liabilities		$ 227,705	$ (198,610)	$ 29,095

(a) Recovery period varies by jurisdiction. See discussion below for additional information regarding our regulatory assets related to winter weather event costs and regulatory liabilities related to federal income tax rate changes.

	Remaining Recovery Period	December 31, 2021 Current	Noncurrent	Total
		(Thousands of dollars)		
Winter weather event costs	(a)	$ 1,536,054	$ 428,023	$ 1,964,077
Under-recovered purchased-gas costs	1 year	31,863	—	31,863
Pension and other postemployment benefit costs	See Note 14	11,507	260,559	272,066
Reacquired debt costs	6 years	812	4,070	4,882
MGP remediation costs	15 years	98	29,841	29,939
Ad-valorem tax	1 year	8,561	—	8,561
WNA	1 year	10,044	—	10,044
Customer credit deferrals	1 year	10,685	—	10,685
Other	1 to 18 years	2,052	2,369	4,421
Total regulatory assets, net of amortization		1,611,676	724,862	2,336,538
Income tax rate changes	(a)	—	(552,928)	(552,928)
Over-recovered purchased-gas costs	1 year	(8,090)	—	(8,090)
Total regulatory liabilities		(8,090)	(552,928)	(561,018)
Net regulatory assets and liabilities		$ 1,603,586	$ 171,934	$ 1,775,520

(a) Recovery period varies by jurisdiction. See discussion below for additional information regarding our regulatory liabilities related to federal income tax rate changes.

Regulatory assets in our consolidated balance sheets, as authorized by various regulatory authorities, are probable of recovery. Base rates and certain riders are designed to provide a recovery of costs during the period such rates are in effect, but do not generally provide for a return on investment for amounts we have deferred as regulatory assets. All of our regulatory assets are subject to review by the respective regulatory authorities during future regulatory proceedings. We are not aware of any evidence that these costs will not be recoverable through either riders, base rates, or securitization.

Winter weather event costs - In February 2021, the U.S. experienced Winter Storm Uri, a historic winter weather event impacting supply, market pricing and demand for natural gas in a number of states, including our service territories of Oklahoma, Kansas, and Texas. During this time, the governors of Oklahoma, Kansas, and Texas each declared a state of emergency, and certain regulatory agencies issued emergency orders that impacted the utility and natural gas industries, including statewide utility curtailment programs and orders requiring jurisdictional natural gas and electric utilities to do all things possible and necessary to ensure that natural gas and electricity utility services continued to be provided to their customers. Due to the historic nature of this winter weather event, we experienced unforeseeable and unprecedented market pricing for natural gas in our Oklahoma, Kansas, and Texas jurisdictions, which resulted in aggregated natural gas purchases for the month of February 2021 of approximately $2.1 billion.

Oklahoma - Beginning in the first quarter 2021, Oklahoma Natural Gas began deferring to a regulatory asset the extraordinary costs associated with this unprecedented winter weather event, including commodity costs, operational costs and carrying costs, in accordance with an order issued by the OCC in March 2021. In April 2021, a bill permitting the state of Oklahoma to pursue securitized financing of extraordinary expenses, such as fuel costs, financing costs and other operational costs incurred by regulated utilities during extreme weather events, was signed into law. This law gives the OCC the authority to approve amounts to be recovered from the issuance of ratepayer-backed securitized bonds by the ODFA.

In April 2021, Oklahoma Natural Gas submitted an initial application requesting a financing order pursuant to the securitization legislation in Oklahoma. In January 2022, the OCC approved the financing order that reflected the terms of a settlement agreement, which included an agreement that all extreme gas purchase and extraordinary costs incurred as a result of Winter Storm Uri were reasonable and prudent and a financing order should be issued to recover these costs through securitization. Pursuant to the securitization statute in Oklahoma, the Oklahoma Supreme Court validated that the bond issuance proposed by the ODFA complied with the securitization statute and the laws of Oklahoma in May 2022.

In August 2022, the ODFA completed the issuance of $1.35 billion in ratepayer-backed bonds with varying scheduled final maturities over 30 years, consistent with the OCC financing order. The bonds are limited and special revenue obligations of the ODFA, payable solely from the securitization bond collateral and are not an obligation of Oklahoma Natural Gas or any of its affiliates.

The proceeds received by Oklahoma Natural Gas were approximately $1.3 billion, which represents the amount of the securitization bonds issued by the ODFA less issuance costs. The receipt of these proceeds represents Oklahoma Natural Gas' recovery of the approximately $1.3 billion of authorized extraordinary natural gas purchase costs and other operational costs incurred during Winter Storm Uri, as well as carrying costs. GAAP does not provide comprehensive recognition and measurement guidance for many forms of government assistance received by business entities. Accordingly, we have accounted for the proceeds received from the ODFA by analogy to International Accounting Standards No. 20, "Accounting for Government Grants and Disclosure of Government Assistance" consistent with a grant related to income. The proceeds received and the corresponding recognition of the deferred regulatory asset have been reflected in cost of natural gas in our consolidated statements of income. As the proceeds reflect the recovery of our winter weather event regulatory asset, there was no material impact to earnings. Beginning September 1, 2022, Oklahoma Natural Gas acts as a servicer, with responsibility for collecting the securitization charges from Oklahoma customers that are then submitted to the ODFA to repay the securitization bonds. The collection and remittance of these funds on behalf of the ODFA are recorded in other current liabilities in our consolidated balance sheets.

Kansas - In March 2021, the KCC issued an order adopting the KCC staff's recommendation to open company-specific dockets to accept each utility's filing of financial impact compliance reports and permit the KCC staff to conduct a review of the utility's compliance report and its actions during Winter Storm Uri. In April 2021, a bill permitting the utilities to pursue securitization to finance extraordinary expenses, such as fuel costs incurred during extreme weather events, was signed into law by the Kansas governor. The law gives the KCC the authority to oversee and authorize the issuance of ratepayer-backed securitized bonds issued by a public utility.

In May 2021, Kansas Gas Service filed a motion in its company-specific docket opened by the KCC, requesting a limited waiver of the penalty provisions of its tariff to eliminate the multipliers in the penalty calculation when calculating the penalties to assess on marketers and individually-balanced transportation customers for their unauthorized natural gas usage during Winter Storm Uri. In March 2022, the KCC issued an order approving a settlement which modified the penalty provisions of Kansas Gas Service's tariffs and included a carrying charge of two percent on amounts due to Kansas Gas Service. Amounts collected from these penalties will reduce the regulatory asset for the winter weather event, up to $52.6 million. Through December 31, 2022, we have collected $50.5 million of these penalties.

In July 2021, Kansas Gas Service submitted its financial plan to the KCC as required by the company-specific docket opened by the KCC in March 2021. The plan includes a proposal for a newly formed, bankruptcy remote subsidiary of the Company to issue securitized utility tariff bonds to recover the extraordinary costs resulting from Winter Storm Uri from Kansas Gas Service's customers. In February 2022, the KCC issued an order approving a unanimous settlement agreement that allows

Kansas Gas Service to recover extraordinary costs, net of any penalties recovered from marketers and individually-balanced transportation customers, plus carrying costs, by seeking a financing order from the KCC for the issuance of securitized utility tariff bonds.

In March 2022, Kansas Gas Service submitted its application for a financing order to the KCC as contemplated by the unanimous settlement agreement, requesting approval to issue securitized utility tariff bonds to recover extraordinary costs resulting from Winter Storm Uri and flexibility to recover the costs. In July 2022, Kansas Gas Service, the KCC Staff and the Citizens' Utility Ratepayer Board reached a settlement agreement for the issuance of a financing order allowing a newly formed, bankruptcy remote subsidiary of the Company to issue securitized utility tariff bonds. In August 2022, the KCC issued an order approving the agreement and also issued a financing order.

As part of the order, we created KGSS-I, a special-purpose, wholly-owned subsidiary of ONE Gas, and filed a registration statement with the SEC, for the purpose of issuing securitized utility tariff bonds. The registration statement was declared effective on November 7, 2022.

In November 2022, KGSS-I issued $336 million of 5.486 percent Securitized Utility Tariff Bonds. KGSS-I used the proceeds from the issuance to purchase the Securitized Utility Tariff Property from Kansas Gas Service, pay for debt issuance costs, and reimburse Kansas Gas Service for upfront securitization costs paid by Kansas Gas Service on behalf of KGSS-I. See Notes 1 and 4 for additional information about the Securitized Utility Tariff Bonds and Note 11 for additional information about the securitization transaction.

Texas - Pursuant to securitization legislation enacted in Texas as a result of Winter Storm Uri and a June 2021 RRC Notice to Gas Utilities, Texas Gas Service submitted an application to the RRC in July 2021, for an order authorizing the amount of extraordinary costs for recovery and other such specifications necessary for the issuance of securitized bonds.

In November 2021, the RRC approved a unanimous settlement agreement among Texas Gas Service, the other natural gas utilities in Texas participating in the securitization process, the staff of the RRC and all intervenors. The settlement agreement provides that all costs incurred by Texas Gas Service to purchase natural gas during Winter Storm Uri were reasonable, necessary and prudently incurred.

In February 2022, the RRC issued a single financing order for Texas Gas Service and other natural gas utilities in Texas participating in the securitization process, which included a determination that the approved costs will be collected from customers over a period of not more than 30 years. The TPFA formed the Texas Natural Gas Securitization Finance Corporation, a new independent public authority, that will issue the securitized bonds, which are expected to be issued by April 2023. At December 31, 2022, Texas Gas Service has deferred approximately $243.1 million in extraordinary costs associated with Winter Storm Uri, which includes $43.8 million attributable to the former West Texas service area. Pursuant to the approved settlement order, Texas Gas Service is collecting the extraordinary costs, including carrying costs, associated with Winter Storm Uri attributable to the former West Texas service area from those customers over a period of three years that began in January 2022.

General - In accordance with these regulatory orders associated with the winter weather event, our regulatory asset totaled approximately $258.2 million in extraordinary costs for natural gas purchases, related financing and carrying costs and other operational costs that have not been recovered at December 31, 2022. The amounts deferred include invoiced costs for natural gas purchases that have not been paid as we work with our suppliers to resolve discrepancies in invoiced amounts. The amounts deferred may be adjusted as the differences are resolved. As these amounts are related to the gas purchase costs associated with Winter Storm Uri, which are deferred, future adjustments to the amounts deferred are not expected to have a material impact on earnings.

Other regulatory assets and liabilities - Purchased-gas costs represent the natural gas costs that have been over- or under- recovered from customers through the purchased-gas cost adjustment mechanisms, and includes natural gas utilized in our operations and premiums paid and any cash settlements received from our purchased natural gas call options.

The OCC, KCC and regulatory authorities in Texas have approved the recovery of pension costs and other postemployment benefits costs through rates for Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service, respectively. The costs recovered through rates are based on the net periodic benefit cost for defined benefit pension and other postemployment costs. Differences, if any, between the net periodic benefit cost, net of deferrals, and the amount recovered through rates are reflected in earnings. We historically have recovered defined benefit pension and other postemployment benefit costs through rates. We believe it is probable that regulators will continue to include the net periodic pension and other postemployment benefit costs in our cost of service.

We amortize reacquired debt costs in accordance with the accounting guidelines prescribed by the OCC and KCC.

See Note 17 for additional information regarding our regulatory assets for MGP remediation costs.

Ad-valorem tax represents the difference in Kansas Gas Service's taxes incurred each year above or below the amount approved in base rates. This difference is deferred as a regulatory asset or liability for a 12-month period. Kansas Gas Service then applies an adjustment to customers' bills to refund the over-collected revenue or bill the under-collected revenue over the subsequent 12 months.

Weather normalization represents revenue over- or under- recovered through the WNA rider in Kansas. This amount is deferred as a regulatory asset or liability for a 12-month period. Kansas Gas Service then applies an adjustment to the customers' bills for 12 months to refund the over-collected revenue or bill the under-collected revenue.

The customer credit deferrals and the regulatory liability for income tax rate changes represents deferral of the effects of enacted federal and state income tax rate changes on our ADIT and the effects of these changes on our rates. See Note 15 for additional information regarding the impact of income tax rate changes during the year ended December 31, 2022.

Recovery through rates resulted in amortization of regulatory assets of approximately $9.4 million, $5.5 million and $3.2 million for the years ended December 31, 2022, 2021 and 2020, respectively.

11. VARIABLE INTEREST ENTITY

KGSS-I is a special-purpose, wholly owned subsidiary of ONE Gas that was formed for the purpose of issuing securitized utility tariff bonds to recover extraordinary costs incurred by Kansas Gas Service resulting from Winter Storm Uri. On November 18, 2022, the securitized financing was complete. KGSS-I's assets cannot be used to settle ONE Gas' obligations and the holders of the Securitized Utility Tariff Bonds have no recourse against ONE Gas. See Notes 1, 4 and 10 for additional information about the securitization financing.

Because KGSS-I's equity at risk is less than 1 percent of its total assets, it is considered to be a variable interest entity. Through its equity ownership interest and role as servicer, ONE Gas has the power to direct the most significant financial and operating activities of KGSS-I, including billing, collections, and remittance of customer cash receipts to enable KGSS-I to service the principal and interest payments due under the Securitized Utility Tariff Bonds. Therefore, ONE Gas is the primary beneficiary of KGSS-I, and as a result, KGSS-I is included in the consolidated financial statements of ONE Gas. No gain or loss was recognized upon initial consolidation.

The following table summarizes the impact of KGSS-I on our consolidated balance sheets:

		December 31, 2022
		(Thousands of dollars)
Restricted cash and cash equivalents	$	**8,446**
Accounts receivable		**4,862**
Securitized intangible asset, net		**323,838**
Current maturities of securitized utility tariff bonds		**20,716**
Accounts payable		**3,204**
Accrued interest		**2,202**
Securitized utility tariff bonds, excluding current maturities, net of issuance costs		**309,343**
Equity	$	**1,681**

The following table summarizes the impact of KGSS-I on our consolidated statements of income:

		Year ended December 31, 2022
		(Thousands of dollars)
Operating revenues	$	**5,769**
Operating expense		**(52)**
Amortization expense		**(3,521)**
Interest income		**6**
Interest expense		**(2,202)**
Income before income taxes	$	—

The following table summarizes the amortization expense related to the securitized intangible asset expected to be recognized in our consolidated statements of income:

For the year ending:		*(Thousands of dollars)*
2023	$	**27,851**
2024	$	**27,843**
2025	$	**29,391**
2026	$	**31,025**
2027	$	**32,751**

12. PROPERTY, PLANT AND EQUIPMENT

The following table sets forth our property, plant and equipment by property type, for the periods indicated:

		December 31, 2022		December 31, 2021
		(Thousands of dollars)		
Natural gas distribution pipelines and related equipment	$	**6,240,236**	$	5,836,066
Natural gas transmission pipelines and related equipment		**661,379**		624,528
General plant and other		**782,870**		712,659
Construction work in process		**150,072**		101,015
Property, plant and equipment		**7,834,557**		7,274,268
Accumulated depreciation and amortization		**(2,205,717)**		(2,083,433)
Net property, plant and equipment	$	**5,628,840**	$	5,190,835

We compute depreciation expense by applying composite, straight-line rates of approximately 2.5 percent to 3.5 percent as approved by various regulatory authorities.

We recorded capitalized interest of $4.5 million, $4.2 million and $4.2 million for the years ended December 31, 2022, 2021 and 2020, respectively. We incurred liabilities for construction work in process that had not been paid at December 31, 2022, 2021 and 2020 of $28.6 million, $25.6 million and $24.3 million, respectively. Such amounts are not included in capital expenditures or in the change of working capital items on our consolidated statements of cash flows.

13. SHARE-BASED PAYMENTS

The ECP provides for the granting of stock-based compensation, including incentive stock options, nonstatutory stock options, stock bonus awards, restricted stock awards, restricted stock unit awards, performance stock awards and performance unit awards to eligible employees and the granting of stock awards to non-employee directors. At December 31, 2022, we have 4.3 million shares of common stock reserved for issuance under the ECP. At December 31, 2022, we had approximately 1.4 million shares available for issuance under the ECP, which reflect shares issued and estimated shares expected to be issued upon vesting of outstanding awards granted under the plan, less forfeitures. The plan allows for the deferral of awards granted in stock or cash, in accordance with the Code section 409A requirements.

Compensation expense for our ECP share-based payment plans was $6.8 million, net of tax benefits of $2.3 million, for 2022, $7.5 million, net of tax benefits of $2.5 million, for 2021, and $7.0 million, net of tax benefits of $2.3 million, for 2020.

Restricted Stock Unit Awards - We have granted restricted stock unit awards to key employees that vest over a service period of generally three years and entitle the grantee to receive shares of our common stock. Restricted stock unit awards granted accrue dividend equivalents in the form of additional restricted stock units prior to vesting. Restricted stock unit awards are measured at fair value as if they were vested and issued on the grant date and adjusted for estimated forfeitures. Compensation expense is recognized on a straight-line basis over the vesting period of the award. A forfeiture rate of 3 percent per year based on historical forfeitures under our share-based payment plans is used.

Performance Stock Unit Awards - We have granted performance stock unit awards to key employees. The shares of common stock underlying the performance stock units vest at the expiration of a service period of generally three years if certain performance criteria are met by us as determined by the Executive Compensation Committee of the Board of Directors. Upon vesting, a holder of performance stock units is entitled to receive a number of shares of common stock equal to a percentage (0 percent to 200 percent) of the performance stock units granted, based on our total shareholder return over the vesting period, compared with the total shareholder return of a peer group of other utilities over the same period.

If paid, the outstanding performance stock unit awards entitle the grantee to receive shares of our common stock. The outstanding performance stock unit awards are equity awards with a market-based condition, which results in the compensation expense for these awards being recognized on a straight-line basis over the requisite service period, provided that the requisite service period is fulfilled, regardless of when, if ever, the market condition is satisfied. The performance stock unit awards granted accrue dividend equivalents in the form of additional performance stock units prior to vesting. The fair value of these performance stock units was estimated on the grant date based on a Monte Carlo model. The compensation expense on these awards will only be adjusted for forfeitures. A forfeiture rate of 3 percent per year based on historical forfeitures under our share-based payment plans is used.

Restricted Stock Unit Award Activity

As of December 31, 2022, there was $3.7 million of total unrecognized compensation expense related to the nonvested restricted stock unit awards, which is expected to be recognized over a weighted-average period of 1.8 years. The following tables set forth activity and various statistics for restricted stock unit awards outstanding under the respective plans for the period indicated:

	Number of Units	Weighted-Average Grant Date Fair Value
Nonvested at December 31, 2021	94,274	$ 82.16
Granted	**56,420**	**$ 76.96**
Vested	**(28,830)**	**$ 78.91**
Forfeited	**(5,231)**	**$ 84.06**
Nonvested at December 31, 2022	**116,633**	**$ 79.32**

	2022	2021	2020
Weighted-average grant date fair value (per share)	**$ 76.96**	$ 72.69	$ 96.21
Fair value of shares granted (thousands of dollars)	**$ 4,342**	$ 3,660	$ 3,005

For the years ended December 31, 2022, 2021 and 2020, the fair value of restricted stock vested was $2.9 million, $3.4 million, and $3.3 million, respectively.

Performance Stock Unit Award Activity

As of December 31, 2022, there was $8.0 million of total unrecognized compensation expense related to the nonvested performance stock unit awards, which is expected to be recognized over a weighted-average period of 1.8 years. The following tables set forth activity and various statistics related to our performance stock unit awards and the assumptions used by us in the valuations of the 2022, 2021 and 2020 grants at the grant date:

	Number of Units		Weighted-Average Grant Date Fair Value
Nonvested at December 31, 2021	198,599	$	90.13
Granted	**87,266**	**$**	**95.80**
Vested	**(63,389)**	**$**	**89.86**
Forfeited	**(7,939)**	**$**	**91.41**
Nonvested at December 31, 2022	**214,537**	**$**	**92.47**

	2022	2021	2020
Volatility (a)	**34.00%**	32.70%	16.40%
Dividend yield	**3.22%**	3.19%	2.25%
Risk-free interest rate (b)	**1.65%**	0.20%	1.40%

(a) - Volatility based on historical volatility over three years using daily stock price observations of our peer utilities.
(b) - Using 3-year treasury rate.

		2022		2021		2020
Weighted-average grant date fair value (per share)	**$**	**95.80**	$	82.51	$	102.77
Fair value of shares granted (thousands of dollars)	**$**	**8,360**	$	8,860	$	6,502

For the years ended December 31, 2022, 2021 and 2020, the fair value of performance stock vested was $5.2 million, $7.2 million, and $10.2 million, respectively.

Employee Stock Purchase Plan

We have reserved a total of 1.25 million shares of common stock for issuance under our ESPP. Employees can choose to have up to 10 percent of their annual base pay withheld to purchase our common stock, subject to terms and limitations of the plan. The purchase price of the stock is 85 percent of the lower of the average market price of our common stock on the grant date or exercise date. Approximately 42 percent, 44 percent and 50 percent of employees participated in the plan in 2022, 2021 and 2020, respectively. For the years ended December 31, 2022, 2021 and 2020, employees purchased 86,657, 89,240, and 92,507 shares, respectively, at an average price of $65.21, $63.41 and $64.77, respectively.

Compensation expense related to our ESPP, before taxes, was $1.1 million for each of the years ended December 31, 2022, 2021 and 2020.

14. EMPLOYEE BENEFIT PLANS

Defined Benefit Pension and Other Postemployment Benefit Plans

Defined Benefit Pension Plans - We have a defined benefit pension plan and a supplemental executive retirement plan, both of which are closed to new participants. Certain employees of the Texas Gas Service division are entitled to benefits under a frozen cash-balance pension plan. We fund our defined benefit pension costs at a level needed to maintain or exceed the minimum funding levels required by the Employee Retirement Income Security Act of 1974, as amended, and the Pension Protection Act of 2006.

Other Postemployment Benefit Plans - We sponsor health and welfare plans that provide postemployment medical and life insurance benefits to certain employees who retire with at least five years of service. The postemployment medical plan is contributory based on hire date, age and years of service, with retiree contributions adjusted periodically, and contains other cost-sharing features such as deductibles and coinsurance.

Actuarial Assumptions - The following table sets forth the weighted-average assumptions used to determine benefit obligations for pension and postemployment benefits for the periods indicated:

	December 31,	
	2022	**2021**
Discount rate - pension plans	**5.60%**	3.05%
Discount rate - other postemployment plans	**5.70%**	3.00%
Compensation increase rate	**3.60% - 5.00%**	3.10% - 5.00%

The following table sets forth the weighted-average assumptions used by us to determine the periodic benefit costs for pension and postemployment benefits for the periods indicated:

	Years Ended December 31,		
	2022	**2021**	**2020**
Discount rate - pension plans	**3.05%/4.55% (a)**	2.80%	3.50%
Discount rate - other postemployment plans	**3.00%**	2.70%	3.40%
Expected long-term return on plan assets - pension plans	**6.40%**	7.15%	7.20%
Expected long-term return on plan assets - other postemployment plans	**5.85%**	7.50%	7.65%
Compensation increase rate	**3.10% - 5.00%**	3.10% - 3.90%	3.10% - 4.00%

(a) Pension plans were remeasured as of April 30, 2022.

We determine our discount rates annually. We estimate our discount rate based upon a comparison of the expected cash flows associated with our future payments under our defined benefit pension and other postemployment obligations to a hypothetical bond portfolio created using high-quality bonds that closely match expected cash flows. Bond portfolios are developed by selecting a bond for each of the next 60 years based on the maturity dates of the bonds. Bonds selected to be included in the portfolios are only those rated by Moody's as AA- or better and exclude callable bonds, bonds with less than a minimum issue size, yield outliers and other filtering criteria to remove unsuitable bonds.

We determine our overall expected long-term rate of return on plan assets based on our review of historical returns and economic growth models. We update our assumed mortality rates to incorporate new tables issued by the Society of Actuaries as needed.

Regulatory Treatment - The OCC, KCC and regulatory authorities in Texas have approved the recovery of pension and other postemployment benefits costs through rates for Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service, respectively. The costs recovered through rates are based on current funding requirements and the net periodic benefit cost for defined benefit pension and other postemployment costs. Differences, if any, between the net periodic benefit cost, net of deferrals, and the amount recovered through rates are reflected in earnings.

We historically have recovered defined benefit pension and other postemployment benefit costs through rates. We believe it is probable that regulators will continue to include the net periodic pension and other postemployment benefit costs in our cost of service.

We capitalize all eligible service cost and non-service cost components pursuant to the accounting requirements of ASC Topic 980 (Regulated Operations) for rate-regulated entities, as these costs are authorized by our regulators to be included in capitalized costs. Noncurrent regulatory assets in our consolidated balance sheets reflect the capitalized non-service cost components of $2.8 million and $6.1 million as of December 31, 2022 and December 31, 2021, respectively. See Note 10 for additional information.

Obligations and Funded Status - The following table sets forth our defined benefit pension and other postemployment benefit plans, benefit obligations and fair value of plan assets for the periods indicated:

	Pension Benefits		Other Postemployment Benefits	
	December 31,		December 31,	
	2022	2021	2022	2021
Changes in Benefit Obligation	*(Thousands of dollars)*			
Benefit obligation, beginning of period	$ **1,049,990**	$ 1,077,641	$ **222,806**	$ 239,530
Service cost	**10,369**	13,811	**1,274**	1,587
Interest cost	**36,150**	29,458	**6,448**	6,251
Plan participants' contributions	**—**	—	**3,035**	3,226
Actuarial loss (gain)	**(259,261)**	(19,587)	**(48,609)**	(8,894)
Benefits paid	**(55,326)**	(51,333)	**(16,612)**	(18,894)
Plan amendments	**2,711**	—	**—**	—
Benefit obligation, end of period	**784,633**	1,049,990	**168,342**	222,806
Change in Plan Assets				
Fair value of plan assets, beginning of period	**1,013,244**	987,583	**231,994**	230,895
Actual return (loss) on plan assets	**(190,484)**	75,999	**(38,432)**	14,786
Employer contributions	**1,527**	995	**1,892**	1,981
Plan participants' contributions	**—**	—	**3,035**	3,226
Benefits paid	**(55,326)**	(51,333)	**(16,612)**	(18,894)
Fair value of assets, end of period	**768,961**	1,013,244	**181,877**	231,994
Benefit Asset (Obligation), net at December 31	$ **(15,672)**	$ (36,746)	**13,535**	$ 9,188
Other noncurrent assets	**5,267**	—	**13,535**	9,188
Current liabilities	**(1,352)**	(1,521)	**—**	—
Noncurrent liabilities	**(19,587)**	(35,225)	**—**	—
Benefit Asset (Obligation), net at December 31	$ **(15,672)**	$ (36,746)	$ **13,535**	$ 9,188

The accumulated benefit obligation for our defined benefit pension plans was $746.8 million and $1.0 billion at December 31, 2022 and 2021, respectively.

For the years ended December 31, 2022 and 2021, the pension benefit obligations experienced actuarial gains of $259.3 million and $19.6 million, respectively, primarily due to the impact of increases in the discount rates used to calculate the benefit obligations.

In 2023, our contributions are expected to be $1.4 million to our defined benefit pension plans, and no contributions are expected to be made to our other postemployment benefit plans.

Components of Net Periodic Benefit Cost - The following tables set forth the components of net periodic benefit cost, prior to regulatory deferrals, for our defined benefit pension and other postemployment benefit plans for the period indicated:

	Pension Benefits		
	Year Ended December 31,		
	2022	2021	2020
	(Thousands of dollars)		
Components of net periodic benefit cost			
Service cost	**$ 10,369**	$ 13,811	$ 12,869
Interest cost (a)	**36,150**	29,458	34,179
Expected return on assets (a)	**(58,528)**	(62,382)	(61,119)
Amortization of unrecognized prior service cost (a)	**248**	—	—
Amortization of net loss (a)	**16,793**	45,523	42,319
Net periodic benefit cost	**$ 5,032**	$ 26,410	$ 28,248

(a) These amounts, net of any amounts capitalized as a regulatory asset since adoption of ASU 2017-07 on January 1, 2018, have been recognized as other income (expense), net in the consolidated statements of income. See Note 16 for additional detail of our other income (expense), net.

	Other Postemployment Benefits		
	Year Ended December 31,		
	2022	2021	2020
	(Thousands of dollars)		
Components of net periodic benefit cost			
Service cost	**$ 1,274**	$ 1,587	$ 1,692
Interest cost (a)	**6,448**	6,251	7,557
Expected return on assets (a)	**(13,181)**	(16,807)	(15,469)
Amortization of unrecognized prior service cost (credit) (a)	**41**	(279)	(117)
Amortization of net loss (a)	**217**	373	173
Net periodic benefit cost (credit)	**$ (5,201)**	$ (8,875)	$ (6,164)

(a) These amounts, net of any amounts capitalized as a regulatory asset since adoption of ASU 2017-07 on January 1, 2018, have been recognized as other income (expense), net in the consolidated statements of income. See Note 16 for additional detail of our other income (expense), net.

We use a December 31 measurement date for our plans. On April 30, 2022, we amended our defined benefit pension plans to change the variable cost of living adjustment for eligible participants to a fixed rate. Accordingly, we remeasured our net benefit obligations as of April 30, 2022, resulting in an adjustment of approximately $7.2 million to our pension expense, net of capitalization and regulatory deferrals, for the year ended December 31, 2022.

Other Comprehensive Income (Loss) - The following table sets forth the amounts recognized in other comprehensive income (loss), net of regulatory deferrals, related to our defined benefit pension benefits for the period indicated:

	Pension Benefits		
	Year Ended December 31,		
	2022	2021	2020
	(Thousands of dollars)		
Net gain (loss) arising during the period	**$ 7,369**	$ 67	$ (2,519)
Amortization of loss	**159**	1,562	1,192
Deferred income taxes	**(1,705)**	(379)	289
Total recognized in other comprehensive income (loss)	**$ 5,823**	$ 1,250	$ (1,038)

Due to our regulatory deferrals, there were no amounts recognized in other comprehensive income (loss) related to our other postemployment benefits for the periods presented.

The tables below set forth the amounts in accumulated other comprehensive loss that had not yet been recognized as components of net periodic benefit expense for the periods indicated:

	Pension Benefits	
	December 31,	
	2022	2021
	(Thousands of dollars)	
Prior service cost	**$ (2,463)**	$ —
Accumulated loss	**(245,290)**	(272,332)
Accumulated other comprehensive loss before regulatory assets	**(247,753)**	(272,332)
Regulatory asset for regulated entities	**246,975**	264,027
Accumulated other comprehensive loss after regulatory assets	**(778)**	(8,305)
Deferred income taxes	**74**	1,778
Accumulated other comprehensive loss, net of tax	**$ (704)**	$ (6,527)

	Other Postemployment Benefits	
	December 31,	
	2022	2021
	(Thousands of dollars)	
Prior service cost	**$ (153)**	$ (194)
Accumulated loss	**(8,557)**	(5,887)
Accumulated other comprehensive loss before regulatory assets	**(8,710)**	(6,081)
Regulatory asset for regulated entities	**8,710**	6,081
Accumulated other comprehensive loss after regulatory assets	**$ —**	$ —

Health Care Cost Trend Rates - The following table sets forth the assumed health care cost-trend rates for the periods indicated:

	2022	**2021**
Health care cost-trend rate assumed for next year	**6.50%**	6.00%
Rate to which the cost-trend rate is assumed to decline (the ultimate trend rate)	**4.50%**	4.50%
Year that the rate reaches the ultimate trend rate	**2030**	2028

Plan Assets - Our investment strategy is to invest plan assets in accordance with sound investment practices that emphasize long-term fundamentals. The goal of this strategy is to maximize investment returns while managing risk in order to meet the plan's current and projected financial obligations. To achieve this strategy, we have established a liability-driven investment strategy to change the allocations as the funded status of the defined benefit pension plan increases. The plan's investments include a diverse blend of various domestic and international equities, investment-grade debt securities which mirror the cash flows of our liability, insurance contracts and alternative investments. The current target allocation for the assets of our defined benefit pension plan is as follows:

Investment-grade bonds	60.0 %
U.S. large-cap equities	14.0 %
Alternative investments	10.0 %
Developed foreign large-cap equities	7.0 %
Mid-cap equities	5.0 %
Emerging markets equities	1.0 %
Small-cap equities	3.0 %
Total	100 %

As part of our risk management for the plans, minimums and maximums have been set for each of the asset classes listed above. All investment managers for the plan are subject to certain restrictions on the securities they purchase and, with the exception of indexing purposes, are prohibited from owning our stock.

The current target allocation for the assets of our other postemployment benefits plan is 90 percent fixed income securities and 10 percent equity securities.

The following tables set forth our pension and other postemployment benefits plan assets by fair value category as of the measurement date:

	Pension Benefits December 31, 2022			
Asset Category	**Level 1**	**Level 2**	**Level 3**	**Total**
		(Thousands of dollars)		
Investments:				
Equity securities (a)	$ **150,027**	$ **—**	$ **—**	$ **150,027**
Government obligations	**—**	**160,799**	**—**	**160,799**
Corporate obligations (b)	**—**	**329,973**	**—**	**329,973**
Cash and money market funds (c)	**4,466**	**22,185**	**—**	**26,651**
Insurance contracts and group annuity contracts	**—**	**—**	**14,480**	**14,480**
Other investments (d)	**—**	**—**	**87,031**	**87,031**
Total assets	$ **154,493**	$ **512,957**	$ **101,511**	$ **768,961**

(a) - This category represents securities of the various market sectors from diverse industries.
(b) - This category represents bonds from diverse industries.
(c) - This category primarily represents money market funds.
(d) - This category represents alternative investments such as hedge funds and other financial instruments.

Asset Category	Pension Benefits December 31, 2021 Level 1	Level 2	Level 3	Total
	(Thousands of dollars)			
Investments:				
Equity securities (a)	$ 223,871	$ —	$ —	$ 223,871
Government obligations	—	205,741	—	205,741
Corporate obligations (b)	—	440,445	—	440,445
Cash and money market funds (c)	3,864	30,546	—	34,410
Insurance contracts and group annuity contracts	—	—	17,301	17,301
Other investments (d)	—	20	91,456	91,476
Total assets	$ 227,735	$ 676,752	$ 108,757	$ 1,013,244

(a) - This category represents securities of the various market sectors from diverse industries.
(b) - This category represents bonds from diverse industries.
(c) - This category primarily represents money market funds.
(d) - This category represents alternative investments such as hedge funds and other financial instruments.

Asset Category	Other Postemployment Benefits December 31, 2022 Level 1	Level 2	Level 3	Total
	(Thousands of dollars)			
Investments:				
Equity securities (a)	**$ 5,983**	**$ —**	**$ —**	**$ 5,983**
Government obligations	**—**	**43,291**	**—**	**43,291**
Corporate obligations (b)	**—**	**38,095**	**—**	**38,095**
Cash and money market funds (c)	**750**	**7,621**	**—**	**8,371**
Insurance contracts and group annuity contracts (d)	**—**	**86,137**	**—**	**86,137**
Total assets	**$ 6,733**	**$ 175,144**	**$ —**	**$ 181,877**

(a) - This category represents securities of the various market sectors from diverse industries.
(b) - This category represents bonds from diverse industries.
(c) - This category primarily represents money market funds.
(d) - This category includes equity securities and bonds held in a captive insurance product.

Asset Category	Other Postemployment Benefits December 31, 2021 Level 1	Level 2	Level 3	Total
	(Thousands of dollars)			
Investments:				
Equity securities (a)	$ 25,577	$ —	$ —	$ 25,577
Government obligations	—	41,366	—	41,366
Corporate obligations (b)	—	41,601	—	41,601
Cash and money market funds (c)	542	12,990	—	13,532
Insurance contracts and group annuity contracts (d)	—	109,918	—	109,918
Total assets	$ 26,119	$ 205,875	$ —	$ 231,994

(a) - This category represents securities of the various market sectors from diverse industries.
(b) - This category represents bonds from diverse industries.
(c) - This category primarily represents money market funds.
(d) - This category includes equity securities and bonds held in a captive insurance product.

Insurance contracts and group annuity contracts include investments in the Immediate Participation Guarantee Fund ("IPG Fund") with John Hancock and are valued at fair value. John Hancock invests the IPG Fund in its general fund portfolio. The contract value of the IPG Fund at the end of the year, which approximates fair value, is estimated. The difference between this estimated balance and the actual balance, as subsequently determined by John Hancock, is charged or credited to the net assets of the plans.

Certain investments that are categorized as money market funds in Level 2 and "Other investments" in Level 3 represent alternative investments such as hedge funds and other financial instruments measured using the net asset value per share (or its equivalent) practical expedient.

The following tables set forth additional information regarding commitments and redemption limitations of these other investments at the periods indicated:

	December 31, 2022 Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
	(in thousands)			*(in days)*
Grosvenor Registered Multi Limited Partnership	**$ 40,160**	**$ —**	**quarterly**	**65**
K2 Institutional Investors II Limited Partnership	**$ 46,871**	**$ —**	**quarterly**	**91**

	December 31, 2021 Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
	(in thousands)			*(in days)*
Grosvenor Registered Multi Limited Partnership	$ 44,818	$ —	quarterly	65
K2 Institutional Investors II Limited Partnership	$ 46,638	$ —	quarterly	91

The following table sets forth the reconciliation of Level 3 fair value measurements of our pension plans for the periods indicated:

	Pension Benefits		
	Insurance Contracts	Other Investments	Total
		(Thousands of dollars)	
January 1, 2021	$ 24,603	$ 87,634	$ 112,237
Unrealized gains	—	1,625	1,625
Unrealized losses	(3,368)	—	(3,368)
Purchases	—	2,197	2,197
Settlements	(3,934)	—	(3,934)
December 31, 2021	$ 17,301	$ 91,456	$ 108,757
Unrealized gains	**1,467**	**—**	**1,467**
Unrealized losses	**—**	**(7,458)**	**(7,458)**
Purchases	**182**	**3,033**	**3,215**
Settlements	**(4,470)**	**—**	**(4,470)**
December 31, 2022	**$ 14,480**	**$ 87,031**	**$ 101,511**

Pension and Other Postemployment Benefit Payments - Benefit payments for our defined benefit pension and other postemployment benefit plans for the year ended December 31, 2022 were $55.3 million and $16.6 million, respectively. The following table sets forth the pension benefits and other postemployment benefits payments expected to be paid in 2023-2032:

	Pension Benefits	Other Postemployment Benefits
Benefits to be paid in:	(Thousands of dollars)	
2023	$ 53,970	$ 15,502
2024	$ 54,807	$ 15,150
2025	$ 55,446	$ 14,878
2026	$ 56,241	$ 14,488
2027	$ 56,546	$ 14,199
2028 through 2032	$ 287,424	$ 65,748

The expected benefits to be paid are based on the same assumptions used to measure our benefit obligations at December 31, 2022, and include estimated future employee service.

Other Employee Benefit Plans

401(k) Plan - We have a 401(k) plan which covers all full-time employees. Employee contributions are discretionary and we match 100 percent of each participant's eligible contribution up to 6 percent of eligible compensation, subject to certain limits. Our contributions to the plan were $15.3 million, $14.3 million and $13.8 million in 2022, 2021 and 2020, respectively.

Effective December 30, 2021, our profit sharing-plan was merged with and into our 401(k) Plan. We plan to make a profit-sharing contribution to the 401(k) Plan each quarter equal to 1 percent of each participant's eligible compensation during the quarter. Additional discretionary profit-sharing contributions may be made at the end of each year. Our profit-sharing contributions made to the plan were $10.9 million, $9.9 million and $9.4 million in 2022, 2021 and 2020, respectively.

15. INCOME TAXES

The following table sets forth our provision for income taxes for the periods indicated:

	Years Ended December 31, 2022	2021	2020
	(Thousands of dollars)		
Current income tax provision (benefit)			
Federal	**$ 61,745**	$ (1,568)	$ 20,129
State	**6,815**	(1,565)	2,965
Total current income tax provision (benefit)	**68,560**	(3,133)	23,094
Deferred income tax provision (benefit)			
Federal	**(22,234)**	37,810	10,757
State	**200**	5,639	7,728
Total deferred income tax provision (benefit)	**(22,034)**	43,449	18,485
Total provision for income taxes	**$ 46,526**	$ 40,316	$ 41,579

The following table is a reconciliation of our income tax provision for the periods indicated:

	Years Ended December 31, 2022	2021	2020
	(Thousands of dollars)		
Income before income taxes	**$ 268,268**	$ 246,750	$ 237,991
Federal statutory income tax rate	**21 %**	21 %	21 %
Provision for federal income taxes	**56,335**	51,817	49,978
State income taxes, net of federal tax benefit	**7,016**	4,074	10,693
Amortization of EDIT regulatory liability	**(17,986)**	(17,289)	(17,031)
Tax (expense) benefit for employee share-based compensation	**350**	(469)	(1,489)
Other, net	**811**	2,183	(572)
Total provision for income taxes	**$ 46,526**	$ 40,316	$ 41,579

As of December 31, 2022, we have no uncertain tax positions. Changes in tax laws or tax rates are recognized in the financial reporting period that includes the enactment date. As a regulated entity, the decrease in ADIT resulting from a change in tax laws or tax rates is recorded as a regulatory liability and is subject to refund to our customers.

In May 2021, a bill amending the Oklahoma state income tax code was signed into law that reduced the state income tax rate to four percent from six percent beginning January 1, 2022. As a result of the enactment of this legislation, we remeasured our ADIT. As a regulated entity, the reduction in ADIT of $29.3 million was recorded as a regulatory liability. The impact of the change in the state income tax rate on Oklahoma Natural Gas' rates, as well as the timing and amount of the impact on the annual crediting mechanism for the EDIT regulatory liability, was included in the March 15, 2022 PBRC filing, as approved in November 2022, and was not material.

Income tax expense reflects credits for the amortization of the regulatory liability associated with EDIT that was returned to customers of $18.0 million and $17.3 million for the years ending December 31, 2022, and 2021, respectively.

The following table sets forth the tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities for the periods indicated:

	December 31, 2022	December 31, 2021
	(Thousands of dollars)	
Deferred tax assets		
Employee benefits and other accrued liabilities	**$ 4,256**	$ 11,126
Regulatory adjustments for enacted tax rate changes	**114,551**	120,051
Net operating loss	**161,320**	424,861
Lease obligation basis	**9,158**	6,906
Purchased-gas cost adjustment	**3,384**	—
Other	**3,014**	12,597
Total deferred tax assets	**295,683**	575,541
Deferred tax liabilities		
Excess of tax over book depreciation	**792,570**	734,051
Winter weather event costs	**121,347**	421,070
Purchased-gas cost adjustment	**—**	37,433
Other regulatory assets and liabilities, net	**71,180**	71,541
Right-of-use asset basis	**9,042**	6,730
Total deferred tax liabilities	**994,139**	1,270,825
Net deferred tax liabilities	**$ 698,456**	$ 695,284

We deduct our purchased gas costs for federal income tax purposes in the period they are paid. As a result of the impacts from government securitization of Winter Storm Uri, we recorded a $299.7 million decrease in our deferred tax liability for the year ended December 31, 2022. At December 31, 2022, we had $152.2 million (tax effected) of federal net operating loss carryforwards and $9.1 million (tax effected) of state net operating loss carryforwards available to offset future taxable income.

We have filed our consolidated federal and state income tax returns for years 2019, 2020 and 2021. We are no longer subject to income tax examination for years prior to 2019.

16. OTHER INCOME AND OTHER EXPENSE

The following table sets forth the components of other income and other expense for the periods indicated:

	Years Ended December 31, 2022	2021	2020
	(Thousands of dollars)		
Net periodic benefit (cost) other than service cost	**$ 3,766**	$ (3,930)	$ (5,071)
Earnings (losses) on investments associated with nonqualified employee benefit plans	**(7,197)**	3,699	4,616
Other, net	**(752)**	(2,976)	(2,565)
Total other expense, net	**$ (4,183)**	$ (3,207)	$ (3,020)

17. COMMITMENTS AND CONTINGENCIES

Leases - See Note 5 of the Notes to Consolidated Financial Statements in this Annual Report for discussion of operating leases.

Environmental Matters - We are subject to multiple laws and regulations regarding protection of the environment and natural and cultural resources, which affect many aspects of our present and future operations. Regulated activities include, but are not limited to, those involving air emissions, storm water and wastewater discharges, handling and disposal of solid and hazardous wastes, wetland preservation, plant and wildlife protection, hazardous materials use, storage and transportation, and pipeline and facility construction. These laws and regulations require us to obtain and/or comply with a wide variety of environmental clearances, registrations, licenses, permits and other approvals. Failure to comply with these laws, regulations, licenses and permits or the discovery of presently unknown environmental conditions may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations. In addition, emission controls and/or other regulatory or permitting mandates under the CAA and other similar federal and state laws could require unexpected capital expenditures. We cannot assure that existing environmental statutes and regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional statutes or regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial condition and results of operations. Our expenditures for environmental investigation and remediation compliance to-date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters had no material effects on earnings or cash flows during 2022, 2021 or 2020.

We own or retain legal responsibility for certain environmental conditions at 12 former MGP sites in Kansas. These sites contain contaminants generally associated with MGP sites and are subject to control or remediation under various environmental laws and regulations. A consent agreement with the KDHE governs all environmental investigation and remediation work at these sites. The terms of the consent agreement require us to investigate these sites and set remediation activities based upon the results of the investigations and risk analysis. Remediation typically involves the management of contaminated soils and may involve removal of structures and monitoring and/or remediation of groundwater. Regulatory closure has been achieved at five of the 12 sites, but these sites remain subject to potential future requirements that may result in additional costs.

We have an AAO that allows Kansas Gas Service to defer and seek recovery of costs necessary for investigation and remediation at, and nearby, these 12 former MGP sites that are incurred after January 1, 2017, up to a cap of $15.0 million, net of any related insurance recoveries. Costs approved for recovery in a future rate proceeding would then be amortized over a 15-year period. The unamortized amounts will not be included in rate base or accumulate carrying charges. Following a determination that future investigation and remediation work approved by the KDHE is expected to exceed $15.0 million, net of any related insurance recoveries, Kansas Gas Service will be required to file an application with the KCC for approval to increase the $15.0 million cap. At December 31, 2022 and 2021, we have deferred $29.8 million and $29.9 million, respectively, for accrued investigation and remediation costs pursuant to our AAO. Kansas Gas Service expects to file an application as soon as practicable after the KDHE approves the plans we have submitted.

We have completed or are addressing removal of the source of soil contamination at all 12 sites and continue to monitor groundwater at seven of the 12 sites according to plans approved by the KDHE. In 2019, we completed a project to remove a source of contamination and associated contaminated materials at the twelfth site where no active soil remediation had previously occurred. Remediation plans concerning various sites were submitted to the KDHE in 2021 and 2020 and the KDHE has provided comments that we are addressing. We are also working on a remediation plan for another of these sites for submission to the KDHE.

We also own or retain legal responsibility for certain environmental conditions at a former MGP site in Texas. At the request of the TCEQ, we began investigating the level and extent of contamination associated with the site under their Texas Risk Reduction Program. A preliminary site investigation revealed that this site contains contaminants generally associated with MGP sites and is subject to control or remediation under various environmental laws and regulations. Impacts have been identified in the soil and groundwater at the site with limited impacts observed in surrounding areas. On April 14, 2022, we submitted a remediation work plan to address the areas impacted to the TCEQ. At December 31, 2022, estimated costs associated with expected remediation activities for this site are not material.

Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters had no material effects on earnings or cash flows during the years ended December 31, 2022, 2021 and 2020. The reserve for remediation of our MGP sites was $12.7 million and $22.8 million at December 31, 2022 and December 31, 2021, respectively. Environmental issues may exist with respect to MGP sites that are unknown to us. Accordingly, future costs are dependent on the final determination and regulatory approval of any remedial actions, the complexity of the site, level of remediation required, changing technology and governmental regulations, and to the extent not recovered by insurance or recoverable in rates from our customers, could be material to our financial condition, results of operations or cash flows.

We are subject to environmental regulation by federal, state and local authorities. Due to the inherent uncertainties surrounding the development of federal and state environmental laws and regulations, we cannot determine with specificity the impact such laws and regulations may have on our existing and future facilities. With the trend toward stricter standards, greater regulation and more extensive permit requirements for the types of assets operated by us, our environmental expenditures could increase in the future, and such expenditures may not be fully recovered by insurance or recoverable in rates from our customers, and those costs may adversely affect our financial condition, results of operations and cash flows.

Pipeline Safety - We are subject to regulation under federal pipeline safety statutes and any analogous state regulations. These include safety requirements for the design, construction, operation, and maintenance of pipelines, including transmission and distribution pipelines. At the federal level, we are regulated by PHMSA. PHMSA regulations require the following for certain pipelines: inspection and maintenance plans; integrity management programs, including the determination of pipeline integrity risks and periodic assessments on certain pipeline segments; an operator qualification program, which includes certain trainings; a public awareness program that provides certain information; and a control room management plan.

As part of regulating pipeline safety, PHMSA promulgates various regulations. In April 2016, PHMSA published a NPRM, the Safety of Gas Transmission & Gathering Lines Rule, in the Federal Register to revise pipeline safety regulations applicable to the safety of onshore natural gas transmission and gathering pipelines. Proposals included changes to pipeline integrity management requirements and other safety-related requirements, which were split into three separate rulemakings. At December 31, 2022, all three final rules have been published and the potential capital and operating expenditures associated with compliance were not material or did not apply to us.

Separately, as part of the Consolidated Appropriations Act, 2021, the PIPES Act of 2020 reauthorized PHMSA through 2023 and directed the agency to move forward with several regulatory actions, including the “Pipeline Safety: Class Location Change Requirements” and the “Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines” proposed rulemakings. Congress has also instructed PHMSA to issue final regulations that will require operators of non-rural gas gathering lines and new and existing transmission and distribution pipeline facilities to conduct certain leak detection and repair programs and to require facility inspection and maintenance plans to align with those regulations. To the extent such rulemakings impose more stringent requirements on our facilities, we may be required to incur expenditures that may be material.

Legal Proceedings - We are a party to various litigation matters and claims that have arisen in the normal course of our operations. While the results of litigation and claims cannot be predicted with certainty, we believe the reasonably possible losses from such matters, individually and in the aggregate, are not material. Additionally, we believe the probable outcome of such matters will not have a material adverse effect on our results of operations, financial position or cash flows.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer (Principal Executive Officer) and Chief Financial Officer (Principal Financial Officer), of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rule 13a-15(e) under the Exchange Act. Based on this evaluation, the Company's Principal Executive Officer and Principal Financial Officer have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this Annual Report based on the evaluation of the controls and procedures required by Rule 13a-15(b) of the Exchange Act.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our Principal Executive Officer and Principal Financial Officer, we evaluated the effectiveness of our internal control over financial reporting based on the framework in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Based on our evaluation under that framework and applicable SEC rules, our management concluded that our internal control over financial reporting was effective as of December 31, 2022.

The effectiveness of our internal control over financial reporting as of December 31, 2022, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein (Item 8).

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting during the quarter ended December 31, 2022, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Not applicable.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors of the Registrant

Information concerning our directors is set forth in our 2023 definitive Proxy Statement and is incorporated herein by this reference.

Executive Officers of the Registrant

Information concerning our executive officers is included in Part I, Item 1, Business, of this Annual Report.

Compliance with Section 16(a) of the Exchange Act

Information on compliance with Section 16(a) of the Exchange Act is set forth in our 2023 definitive Proxy Statement and is incorporated herein by this reference.

Code of Ethics

Information concerning the code of ethics, or code of business conduct, is set forth in our 2023 definitive Proxy Statement and is incorporated herein by this reference.

Nominating Procedures

Information concerning the nominating procedures is set forth in our 2023 definitive Proxy Statement and is incorporated herein by this reference.

The Audit Committee

Information concerning the Audit Committee is set forth in our 2023 definitive Proxy Statement and is incorporated herein by this reference.

The Audit Committee Financial Experts

Information concerning the Audit Committee Financial Experts is set forth in our 2023 definitive Proxy Statement and is incorporated herein by this reference.

The Executive Compensation Committee

Information concerning the Executive Compensation Committee is set forth in our 2023 definitive Proxy Statement and is incorporated herein by this reference.

The Corporate Governance Committee

Information concerning the Corporate Governance Committee is set forth in our 2023 definitive Proxy Statement and is incorporated herein by this reference.

The Executive Committee

Information concerning the Executive Committee is set forth in our 2023 definitive Proxy Statement and is incorporated herein by this reference.

Committee Charters

The full text of our Audit Committee charter, Executive Compensation Committee charter, Corporate Governance Committee charter and Executive Committee charter are published on and may be printed from our website at www.onegas.com and are also available from our corporate secretary upon request.

ITEM 11. EXECUTIVE COMPENSATION

Information on executive compensation is set forth in our 2023 definitive Proxy Statement and is incorporated herein by this reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Security Ownership of Certain Beneficial Owners

Information concerning the ownership of certain beneficial owners is set forth in our 2023 definitive Proxy Statement and is incorporated herein by this reference.

Security Ownership of Management

Information on security ownership of directors and officers is set forth in our 2023 definitive Proxy Statement and is incorporated herein by this reference.

Equity Compensation Plan Information

Information on equity compensation plans is set forth in our 2023 definitive Proxy Statement and is incorporated herein by this reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information on certain relationships and related transactions and director independence is set forth in our 2023 definitive Proxy Statement and is incorporated herein by this reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information on the principal accountant's fees and services is set forth in our 2023 definitive Proxy Statement and is incorporated herein by this reference.

PART IV.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(1) Consolidated Financial Statements		Page No.
(a)	Report of Independent Registered Public Accounting Firm (PCAOB ID: 238)	39-40
(b)	Consolidated Statements of Income for the years ended December 31, 2022, 2021 and 2020	42
(c)	Consolidated Statements of Comprehensive Income for the years ended December 31, 2022, 2021 and 2020	43
(d)	Consolidated Balance Sheets as of December 31, 2022 and 2021	44-45
(e)	Consolidated Statements of Cash Flows for the years ended December 31, 2022, 2021 and 2020	46
(f)	Consolidated Statements of Equity for the years ended December 31, 2022, 2021 and 2020	47
(g)	Notes to Consolidated Financial Statements	48-78

(2) Consolidated Financial Statements Schedules

All schedules have been omitted because of the absence of conditions under which they are required.

(3) Exhibits

3.1	Amended and Restated Certificate of Incorporation of ONE Gas, Inc., dated May 24, 2018 (incorporated by reference to Exhibit 3.1 to ONE Gas, Inc.'s Current Report on Form 8-K filed on May 30, 2018 (File No. 1-36108)).
3.2	Amended and Restated By-Laws of ONE Gas, Inc. dated February 21, 2023 (incorporated by reference to Exhibit 3.1 to ONE Gas, Inc.'s Current Report on Form 8-K filed on February 21, 2023 (File No. 1-36108)).
3.3	Amended and Restated Limited Liability Company Agreement of Kansas Gas Service Securitization I, L.L.C., dated as of November 16, 2022 (incorporated by reference to Exhibit 3.3 to ONE Gas, Inc.'s Current Report on Form 8-K filed on November 18, 2022 (File No. 1-36108)).
4.1	Form of Common Stock Certificate (incorporated by reference to Exhibit 4.2 to ONE Gas, Inc.'s Registration Statement on Form 10, Amendment No. 2 filed on December 23, 2013 (File No. 1-36108)).
4.2	Indenture, dated January 27, 2014, between ONE Gas, Inc. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.1 to ONE Gas, Inc.'s Current Report on Form 8-K filed on January 30, 2014 (File No. 1-36108)).
4.3	Supplemental Indenture No. 1, dated January 27, 2014, between ONE Gas, Inc. and U.S. Bank National Association, as trustee, with respect to the 2.070% Senior Notes due 2019, the 3.610% Senior Notes due 2024 and the 4.685% Senior Notes due 2044-(incorporated by reference to Exhibit 10.2 to ONE Gas, Inc.'s Current Report on Form 8-K filed on January 30, 2014 (File No. 1-36108)).
4.4	Supplemental Indenture No. 2, dated November 5, 2018, among ONE Gas, Inc. and U.S. Bank National Bank Association, as trustee, with respect to the 4.50% Senior Notes due 2048 (incorporated by reference to Exhibit 4.2 to ONE Gas, Inc.'s Current Report on Form 8-K filed on November 6, 2018 (File No. 1-36108)).

4.5	Supplemental Indenture No. 3, dated May 4, 2020, among ONE Gas, Inc. and U.S. Bank National Bank Association, as trustee, with respect to the 2.00% Senior Notes due 2030 (incorporated by reference to Exhibit 4.2 to ONE Gas, Inc.'s Current Report on Form 8-K filed on May 4, 2020 (File No. 1-36108)).
4.6	Fourth Supplemental Indenture, dated as of March 11, 2021, between ONE Gas, Inc. and U.S. Bank National Association, as trustee, with respect to the 0.85% Senior Notes due 2023 and 1.10% Senior Notes due 2024 (incorporated by reference to Exhibit 4.2 to ONE Gas, Inc.'s Current Report on Form 8-K filed on March 11, 2021 (File No. 1-36108)).
4.7	Fifth Supplemental Indenture, dated as of March 11, 2021, between ONE Gas, Inc. and U.S. Bank National Association, as trustee, with respect to the Floating Rate Senior Notes due 2023 (incorporated by reference to Exhibit 4.3 to ONE Gas, Inc.'s Current Report on Form 8-K filed on March 11, 2021 (File No. 1-36108)).
4.8	Description of the Registrant's securities registered pursuant to Section 12 of the Securities Act of 1934 (incorporated by reference to Exhibit 4.6 to ONE Gas, Inc.'s Annual Report on Form 10-K filed on February 26, 2021 (File No. 1-36108)).
4.9	Sixth Supplemental Indenture, dated as of August 8, 2022, between ONE Gas, Inc. and U.S. Bank Trust Company, National Association, as trustee, with respect to the 4.25% Notes due 2032 (incorporated by reference to Exhibit 4.2 of ONE Gas Inc.'s Current Report on Form 8-K filed on August 8, 2022 (File No. 1-36108)).
4.10	Indenture by and among Kansas Gas Service Securitization I, L.L.C., U.S. Bank Trust Company, National Association, as Indenture Trustee, and U.S. Bank National Association, as Securities Intermediary (including the form of the Securitized Utility Tariff Bonds and the Series Supplement), dated as of November 18, 2022 (incorporated by reference to Exhibit 4.1 to ONE Gas, Inc.'s Current Report on Form 8-K filed on November 18, 2022 (File No. 1-36108)).
4.11	Series Supplement by and among Kansas Gas Service Securitization I, L.L.C. and U.S. Bank Trust Company, National Association, as Indenture Trustee, dated as of November 18, 2022 (incorporated by reference to Exhibit 4.2 to ONE Gas, Inc.'s Current Report on Form 8-K filed on November 18, 2022 (File No. 1-36108)).
10.1*	Form of ONE Gas, Inc. Indemnification Agreement between ONE Gas, Inc. and ONE Gas, Inc. officers and directors (incorporated by reference to Exhibit 10.5 to ONE Gas, Inc.'s Registration Statement on Form 10 filed on October 1, 2013 (File No. 1-36108)).
10.2*	ONE Gas, Inc. Pre-2005 Nonqualified Deferred Compensation Plan (incorporated by reference to Exhibit 10.7 to ONE Gas, Inc.'s Registration Statement on Form 10, Amendment No. 2 filed on December 23, 2013 (File No. 1-36108)).
10.3*	ONE Gas, Inc. Nonqualified Deferred Compensation Plan (incorporated by reference to Exhibit 10.8 to ONE Gas, Inc.'s Registration Statement on Form 10, Amendment No. 2 filed on December 23, 2013 (File No. 1-36108)).
10.4*	ONE Gas, Inc. Pre-2005 Supplemental Executive Retirement Plan (incorporated by reference to Exhibit 10.9 to ONE Gas, Inc.'s Registration Statement on Form 10, Amendment No. 2 filed on December 23, 2013 (File No. 1-36108)).
10.5*	ONE Gas, Inc. Supplemental Executive Retirement Plan, as amended and restated effective December 1, 2017 (incorporated by reference to Exhibit 10.8 to ONE Gas, Inc.'s Annual Report on Form 10-K filed on February 22, 2018 (File No. 1-36108)).
10.6*	ONE Gas, Inc. Officer Change in Control Severance Plan (incorporated by reference to Exhibit 10.12 to ONE Gas, Inc.'s Registration Statement filed on Form 10, Amendment No. 2 filed on December 23, 2013 (File No. 1-36108)).

10.7*	ONE Gas, Inc. Equity Compensation Plan, as amended and restated effective December 1, 2017 (incorporated by reference to Exhibit 10.11 to ONE Gas, Inc.'s Annual Report on Form 10-K filed on February 22, 2018 (File No. 1-36108)).
10.8*	Form of 2019 Restricted Unit Award Agreement (incorporated by reference to Exhibit 10.12 to ONE Gas, Inc.'s Annual Report on Form 10-K filed on February 20, 2019 (File No. 1-36108)).
10.9*	Form of 2019 Performance Unit Award Agreement (incorporated by reference to Exhibit 10.13 to ONE Gas, Inc.'s Annual Report on Form 10-K filed on February 20, 2019 (File No. 1-36108)).
10.10*	Form of 2023 Restricted Unit Award Agreement.
10.11*	Form of 2023 Performance Unit Award Agreement.
10.12	Extension Agreement dated as of October 5, 2018, among ONE Gas, Inc., Bank of America, N.A., as administrative agent, swing line lender, a letter of credit issuer and a lender, and the other lenders and letter of credit issuers parties thereto (incorporated by reference to Exhibit 10.1 to ONE Gas Inc's Current Report on Form 8-K filed on October 5, 2018 (File No. 1-36108)).
10.13*	ONE Gas, Inc. Amended and Restated Employee Stock Purchase Plan (incorporated by reference to Exhibit 10.16 to ONE Gas, Inc.'s Annual Report on Form 10-K filed on February 20, 2020 (File No. 1-36108)).
10.14	Credit Agreement, dated as of April 7, 2020, among ONE Gas, Inc., Bank of America, N.A., as administrative agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to ONE Gas, Inc.'s Current Report on Form 8-K filed on April 7, 2020 (File No. 1-36108)).
10.15	Form of Commercial Paper Dealer Agreement (incorporated by reference to Exhibit 10.1 to ONE Gas, Inc.'s Current Report on Form 8-K filed on September 10, 2014 (File No. 1-36108)).
10.16*	Form of 2020 Performance Unit Award Agreement (incorporated by reference to Exhibit 10.20 to ONE Gas, Inc.'s Annual Report on Form 10-K filed on February 20, 2020 (File No. 1-36108)).
10.17*	Form of 2020 Restricted Unit Award Agreement (incorporated by reference to Exhibit 10.21 to ONE Gas, Inc.'s Annual Report on Form 10-K filed on February 20, 2020 (File No. 1-36108)).
10.18	Equity Distribution Agreement, dated as of February 26, 2020, among ONE Gas, Inc. and Morgan Stanley & Co. LLC, BofA Securities, Inc., and Mizuho Securities USA LLC, acting as managers; Morgan Stanley & Co. LLC, Bank of America, N.A. and Mizuho Securities Americas LLC, acting as forward purchasers; and Morgan Stanley & Co. LLC, BofA Securities, Inc. and Mizuho Securities USA LLC, acting as forward sellers (incorporated by reference to Exhibit 1.1 to ONE Gas, Inc.'s Current Report on Form 8-K filed on February 26, 2020 (File No. 1-36108)).
10.19	Form of Master Forward Sale Confirmation (incorporated by reference to Exhibit 1.2 to ONE Gas, Inc.'s Current Report on Form 8-K filed on February 26, 2020 (File No. 1-36108)).
10.20*	Form of 2021 Restricted Unit Award Agreement (incorporated by reference to Exhibit 10.28 to ONE Gas, Inc.'s Annual Report on Form 10-K filed on February 26, 2021 (File No. 1-36108)).
10.21*	Form of 2021 Performance Unit Award Agreement (incorporated by reference to Exhibit 10.29 to ONE Gas, Inc.'s Annual Report on Form 10-K filed on February 26, 2021 (File No. 1-36108)).
10.22	Amended and Restated Credit Agreement, dated as of October 5, 2017, among ONE Gas, Inc., Bank of America, N.A., as administrative agent, swingline lender and a letter of credit issuer, and the other lenders and letter of credit issuers parties thereto (incorporated by reference to Exhibit 10.1 to ONE Gas, Inc.'s Current Report on Form 8-K filed on October 6, 2017 (File No. 1-36108)).

10.23*	ONE Gas, Inc. Nonqualified Deferred Compensation Plan, as amended and restated effective January 1, 2018 (incorporated by reference to Exhibit 10.28 to ONE Gas, Inc.'s Annual Report on Form 10-K filed February 22, 2018 (File No. 1-36108)).
10.24	First Amendment and Extension Agreement, dated as of October 4, 2019, among ONE Gas, Inc., Bank of America, N.A., as administrative agent, swing line lender, a letter of credit issuer and a lender, and the other lenders and letter of credit issuers parties thereto (incorporated by reference to Exhibit 10.1 to ONE Gas, Inc.'s Current Report on Form 8-K filed on October 4, 2019 (File No. 1-36108)).
10.25*	ONE Gas, Inc. Amended and Restated Equity Compensation Plan (2018) (incorporated by reference to Appendix A to ONE Gas, Inc.'s Definitive Proxy Statement on Schedule 14A filed on April 4, 2018 (File No. 1-36108)).
10.26*	ONE Gas, Inc. Amended and Restated Annual Officer Incentive Plan, effective January 1, 2020 (incorporated by reference to Exhibit 10.31 to ONE Gas, Inc.'s Annual Report on Form 10-K filed on February 20, 2020 (File No. 1-36108)).
10.27*	Form of 2022 Restricted Unit Award Agreement (incorporated by reference to Exhibit 10.28 to ONE Gas, Inc's Annual Report on Form 10-K filed on February 24, 2022 (File No. 1-36108)).
10.28*	Form of 2022 Performance Unit Award Agreement (incorporated by reference to Exhibit 10.29 to ONE Gas, Inc's Annual Report on Form 10-K filed on February 24, 2022 (File No. 1-36108)).
10.29*	Form of 2021 Restricted Unit Award Agreement dated June 2021 (incorporated by reference to Exhibit 10.30 to ONE Gas, Inc's Annual Report on Form 10-K filed on February 24, 2022 (File No. 1-36108)).
10.30*	Form of 2021 Performance Unit Award Agreement dated June 2021 (incorporated by reference to Exhibit 10.31 to ONE Gas, Inc's Annual Report on Form 10-K filed on February 24, 2022 (File No. 1-36108)).
10.31*	Form of 2021 Restricted Unit Award Agreement dated September 2021 (incorporated by reference to Exhibit 10.32 to ONE Gas, Inc's Annual Report on Form 10-K filed on February 24, 2022 (File No. 1-36108)).
10.32*	Form of 2021 Performance Unit Award Agreement dated September 2021 (incorporated by reference to Exhibit 10.33 to ONE Gas, Inc's Annual Report on Form 10-K filed on February 24, 2022 (File No. 1-36108)).
10.33*	Form of 2020 Restricted Unit Award Agreement dated July 2020 (incorporated by reference to Exhibit 10.30 to ONE Gas, Inc.'s Annual Report on Form 10-K filed February 26, 2021 (File No. 1-36108)).
10.34*	ONE Gas Inc. Annual Officer Incentive Plan, effective January 1, 2019 (incorporated by reference to Exhibit 10.30 to ONE Gas, Inc.'s Annual Report on Form 10-K filed February 20, 2019 (File No. 1-36108)).
10.35	Credit Agreement, dated as of February 22, 2021, among ONE Gas, Inc., the lenders from time to time party thereto and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 to ONE Gas Inc.'s Current Report on Form 8-K filed on February 22, 2021 (File No. 1-36108)).
10.36	Credit Agreement, dated as of March 16, 2021, among ONE Gas, Inc., the lenders from time to time party thereto and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 to ONE Gas, Inc.'s Current Report on Form 8-K filed on March 16, 2021 (File No. 1-36108)).
10.37*	ONE Gas, Inc. Nonqualified Deferred Compensation Plan, as amended and restated effective January 1, 2022 (incorporated by reference to Exhibit 10.1 to ONE Gas, Inc.'s Quarterly Report on Form 10-Q filed on November 2, 2021 (File No. 1-36108)).
10.38*	ONE Gas, Inc. Amended and Restated Employee Stock Purchase Plan (incorporated by reference to Appendix A to ONE Gas, Inc.'s Definitive Proxy Statement on Schedule 14A filed on April 7, 2021 (File No. 1-36108)).

10.39	First Amendment to Second Amended and Restated Credit Agreement, dated as of March 16, 2022, among ONE Gas, Inc., Bank of America, N.A., as administrative agent, swing line lender and letter of credit issuer, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to ONE Gas, Inc.'s Current Report on Form 8-K filed on March 17, 2022 (File No. 1-36108)).
10.40	Securitization Property Purchase and Sale Agreement dated as of August 25, 2022 by and between the Oklahoma Development Finance Authority, as Issuer, and Oklahoma Natural Gas Company, a division of ONE Gas, Inc., as Seller (incorporated by reference to Exhibit 10.1 of ONE Gas, Inc.'s Current Report on Form 8-K filed on August 26, 2022 (File No. 1-36108)).
10.41	ONE Gas, Inc. Deferred Compensation Plan for Non-Employee Directors, amended and restated effective July 18, 2022 (incorporated by reference to Exhibit 10.3 of ONE Gas, Inc.'s Quarterly Report on Form 10-Q filed on November 1, 2022 (File No. 1-36108)).
10.42	Securitized Utility Tariff Property Servicing Agreement between Kansas Gas Service Securitization I, L.L.C. and Kansas Gas Service, a Division of ONE Gas, Inc., as Servicer, dated as of November 18, 2022 (incorporated by reference to Exhibit 10.1 to ONE Gas, Inc.'s Current Report on Form 8-K filed on November 18, 2022 (File No. 1-36108)).
10.43	Securitized Utility Tariff Property Purchase and Sale Agreement between Kansas Gas Service Securitization I, L.L.C. and Kansas Gas Service, a Division of ONE Gas, Inc., as Seller, dated as of November 18, 2022 (incorporated by reference to Exhibit 10.2 to ONE Gas, Inc.'s Current Report on Form 8-K filed on November 18, 2022 (File No. 1-36108)).
10.44	Administration Agreement between Kansas Gas Service Securitization I, L.L.C. and Kansas Gas Service, a Division of ONE Gas, Inc., as Administrator, dated as of November 18, 2022 (incorporated by reference to Exhibit 10.3 to ONE Gas, Inc.'s Current Report on Form 8-K filed on November 18, 2022 (File No. 1-36108)).
21.1	Subsidiaries of ONE Gas, Inc.
23.1	Consent of Independent Registered Public Accounting Firm - PricewaterhouseCoopers LLP.
31.1	Certification of Robert S. McAnnally pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Caron A. Lawhorn pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Robert S. McAnnally pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).
32.2	Certification of Caron A. Lawhorn pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).

101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	XBRL Schema Document.
101.CAL	XBRL Calculation Linkbase Document.
101.LAB	XBRL Label Linkbase Document.
101. PRE	XBRL Presentation Linkbase Document.
101.DEF	XBRL Extension Definition Linkbase Document.
104	Cover Page Interactive Data File (embedded within the Inline XBRL document and contained in Exhibit 101).

* Management contract or compensatory plan or arrangement

Attached as Exhibit 101 to this Annual Report are the following XBRL-related documents: (i) Document and Entity Information; (ii) Consolidated Statements of Income for the years ended December 31, 2022, 2021 and 2020; (iii) Consolidated Statements of Comprehensive Income for the years ended December 31, 2022, 2021 and 2020; (iv) Consolidated Balance Sheets as of December 31, 2022 and 2021; (v) Consolidated Statements of Cash Flows for the years ended December 31, 2022, 2021 and 2020; (vi) Consolidated Statements of Equity for the years ended December 31, 2022, 2021 and 2020; and (vii) Notes to Consolidated Financial Statements.

We also make available on our website the Interactive Data Files submitted as Exhibit 101 to this Annual Report.

ITEM 16. FORM 10-K SUMMARY

None.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Exchange Act, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: February 23, 2023

ONE Gas, Inc.
Registrant

By: /s/ Caron A. Lawhorn
Caron A. Lawhorn
Senior Vice President and
Chief Financial Officer

Pursuant to the requirements of the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on this 23rd day of February 2023.

/s/ John W. Gibson John W. Gibson Chairman of the Board	/s/ Robert S. McAnnally Robert S. McAnnally President, Chief Executive Officer and Director
/s/ Caron A. Lawhorn Caron A. Lawhorn Senior Vice President and Chief Financial Officer	/s/ Brian F. Brumfield Brian F. Brumfield Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)
/s/ Robert B. Evans Robert B. Evans Director	/s/ Tracy E. Hart Tracy E. Hart Director
/s/ Michael G. Hutchinson Michael G. Hutchinson Director	/s/ Pattye L. Moore Pattye L. Moore Director
/s/ Eduardo A. Rodriguez Eduardo A. Rodriguez Director	/s/ Douglas H. Yaeger Douglas H. Yaeger Director

Exhibit 10.10

ONE GAS, INC.

RESTRICTED UNIT AWARD AGREEMENT

This Restricted Unit Award Agreement (this "Agreement") is made and entered into as of February 20, 2023 (the "Grant Date") by and between ONE Gas, Inc., an Oklahoma corporation (the "Company") and the "Participant" named below.

Participant: %%FIRST_NAME_MIDDLE_NAME_LAST_NAME%-%

WHEREAS, the Company has adopted the ONE Gas, Inc. Amended and Restated Equity Compensation Plan (2018), as amended from time to time (the "Plan"), pursuant to which Restricted Unit Awards may be granted; and

WHEREAS, the Executive Compensation Committee of the Board of Directors (the "Committee") has determined that it is in the best interests of the Company and its shareholders to grant the Restricted Unit Award provided for herein.

NOW, THEREFORE, the parties hereto, intending to be legally bound, agree as follows:

1. Grant of Restricted Units.

1.1 The Company hereby grants to the Participant an award consisting of the number of Restricted Units specified below ("Restricted Units" or the "Award") on the terms and conditions set forth in this Agreement and the Plan.

Number of Restricted Units: %%TOTAL_SHARES_GRANTED,'999,999,999'%-%

Each Restricted Unit represents the right to receive one share of the Company's common stock ("Share") or, at the Company's option, an amount of cash as set forth in Section 6.3, in either case, at the times and subject to the conditions set forth herein. Capitalized terms that are used but not defined herein have the meanings set forth in the Plan.

1.2 The Restricted Units shall be credited to a separate account maintained for the Participant on the books and records of the Company (the "Account"). All amounts credited to the Account shall continue for all purposes to be part of the general assets of the Company.

2. Consideration. The Award is granted in consideration of the Participant's continued employment with the Company.

3. Vesting.

3.1 General. Subject to Participant's continuous employment with the Company during the period beginning on the Grant Date and ending on February 14, 2026 (the "Restricted Period") and subject to the terms of this Agreement, the Participant will vest in such amounts and at such times as are set forth below:

Vesting Date	Percentage of Award That Vests
February 14, 2026	100%

For purposes of this Agreement, employment with any Subsidiary of the Company shall be treated as employment with the Company. Likewise, a termination of employment shall not be deemed to occur by reason of a transfer of employment between the Company and any Subsidiary.

Restricted Units that vest pursuant to the terms of this Agreement, including Sections 3.2 and 3.3 below, are referred to as "Vested Units" and the date upon which the Restricted Units vest is referred to as a "Vesting Date." Unless and until the Restricted Units have vested, Participant will have no right to receive any Shares subject thereto. Prior to the actual delivery of any Shares, the Award will represent an unsecured obligation of the Company, payable only from the Company's general assets.

3.2 Termination of Employment.

(a) If the Participant's employment with the Company is terminated prior to the end of the Restricted Period by the Company without Cause or on account of the Participant's Retirement, Total Disability or death, the Participant will vest in a pro-rata portion of the Restricted Units as of the Participant's termination date. The pro-rata portion of the Restricted Units that vest will be determined by multiplying the number of Restricted Units granted hereunder by a fraction, which fraction shall be equal to the number of full calendar months which have elapsed under the Restricted Period at the time of such termination of employment divided by thirty-six. If the Participant's employment with the Company terminates for any other reason, Participant shall immediately forfeit any and all Restricted Units that have not vested or do not vest on or prior to the Participant's termination date and neither the Company nor any Subsidiary shall have any further obligations to the Participant under this Agreement. For purposes of this Agreement:

(i) "Cause" will mean any of the following: (i) the Participant's conviction in a court of law of a felony, or any crime or offense involving misuse or misappropriation of money or property, (ii) the Participant's violation of any covenant, agreement or obligation not to disclose confidential information regarding the business of the Company (or Subsidiary), (iii) any violation by the Participant of any covenant not to compete with the Company (or Subsidiary), (iv) any act of dishonesty by the Participant which adversely effects the business of the Company (or Subsidiary), (v) any willful or intentional act of the Participant which adversely affects the business of, or reflects unfavorably on the reputation of the Company (or Subsidiary), (vi) the Participant's use of alcohol or drugs which interferes with the Participant's duties as an employee of the

Company (or Subsidiary), or (vii) the Participant's failure or refusal to perform the specific directives of the Company's Board, or its officers which directives are consistent with the scope and nature of the Participant's duties and responsibilities with the existence and occurrence of all of such causes to be determined by the Company, in its sole discretion; provided, that nothing contained in the foregoing provisions of this Section shall be deemed to interfere in any way with the right of the Company (or Subsidiary), which is hereby acknowledged, to terminate the Participant's employment at any time without Cause.

(ii) "Retirement" means a voluntary termination of employment of the Participant with the Company by the Participant if at the time of such termination of employment the Participant has both completed five (5) years of service with the Company and attained age fifty (50).

(iii) "Total Disability" means that the Participant is permanently and totally disabled and unable to engage in any substantial gainful activity by reason of a medically determinable physical or mental impairment which can be expected to result in death or which has lasted or can be expected to last for a continuous period of not less than twelve (12) months, and has established such disability to the extent and in the manner and form as may be required by the Committee.

3.3 Change in Control. If a Change in Control occurs prior to the end of the Restricted Period and the Participant is employed by the Company at the time of the Change in Control, but subsequently terminates prior to the end of the Restricted Period based on an involuntary termination (without cause) or a voluntary termination with "good reason" within 24 months of the Change in Control date, then the Participant shall become one hundred percent (100%) vested in the Award upon the date of the termination due to the Change in Control. Good reason includes:

- Demotion or material reduction of authority or responsibility;
- Material reduction in base salary;
- Material reduction in annual incentive or LTI targets;
- Relocation of greater than 35 miles; or
- Failure of a successor company to assume the change-in-control plan.

Notwithstanding the foregoing, the provisions set forth in the Plan applicable to a Change in Control shall apply to the Award, and in the event of a Change in Control, the Committee, in its sole discretion and to the extent permitted by Section 409A, may take such actions as it deems appropriate pursuant to the Plan. For purposes of this Agreement, the term "Change in Control" shall have the same meaning as provided in the Plan unless the Award is or becomes subject to Section 409A, in which event "Change in Control" shall have the meaning provided in Section 409A and the related Treasury Regulations.

4. Transfer Restrictions.

4.1 Except as provided in Section 4.2, during the Restricted Period and until such time as the Shares underlying the Vested Units have been issued, the Restricted Units, related Shares or the rights relating thereto may not be sold, pledged, assigned, transferred or otherwise disposed of by the Participant in any manner other than by will or by laws of descent and distribution. Except as provided in Section 4.2, any attempt to sell, pledge, assign, transfer or otherwise dispose of the Restricted Units, related Shares or the rights relating thereto shall be wholly ineffective and, if any such attempt is made, the Restricted Units, related Shares or the rights relating thereto will be forfeited by the Participant and all of the Participant's rights to such units or related Shares shall immediately terminate without any payment or consideration by the Company.

4.2 Notwithstanding the foregoing, the Participant may transfer any part or all of the Participant's rights in the Restricted Units to members of the Participant's immediate family, or to one or more trusts for the benefit of such immediate family members, or partnerships in which such immediate family members are the only partners if the Participant does not receive any consideration for the transfer. In the event of any such transfer, Restricted Units shall continue to be subject to the same terms and conditions otherwise applicable hereunder and under the Plan immediately prior to transfer, except that such rights shall not be further transferable by the transferee inter vivos, except for transfer back to the Participant. For any such transfer to be effective, the Participant must provide prior written notice thereof to the Committee and the Participant shall furnish to the Committee such information as it may request with respect to the transferee and the terms and conditions of any such transfer. For purposes of this Agreement, "immediate family" shall mean the Participant's spouse, children and grandchildren.

5. Dividend Equivalents. During the Restricted Period, the Participant's Account shall be credited with an amount equal to all ordinary cash dividends ("Dividend Equivalents") that would have been paid to the Participant if one Share had been issued on the Grant Date for each Restricted Unit granted to the Participant as set forth in this Agreement. The Dividend Equivalents credited to the Participant's Account will be deemed to be reinvested in additional Restricted Units (or fractional units) and will be subject to the same terms and conditions as the Restricted Units to which they are attributable and shall vest or be forfeited (if applicable) and settled at the same time as the Restricted Units to which they are attributable. Such additional Restricted Units shall also be credited with additional Dividend Equivalents as any further dividends are declared.

6. Settlement of Vested Units; Distribution or Payment.

6.1 Vested Units shall be settled and distributed in Shares (either in book-entry form or otherwise) or, at the Company's option, paid in an amount of cash as set forth in Section 6.3. All distributions in Shares shall be in the form of whole Shares, and any fractional Share shall be distributed in cash in an amount equal to the value of such fractional Share determined based on the Fair Market Value of a Share on the Vesting Date.

6.2 Subject to Section 9 and Section 22.2, the Company shall distribute to the Participant the number of Shares equal to the number of Vested Units within 75 days after the applicable Vesting Date.

6.3 If the Company elects to settle the Participant's Vested Units in cash, the amount of cash payable with respect to each Vested Unit shall be equal to the Fair Market Value of a Share on the Vesting Date.

6.4 To the extent that the Participant does not vest in any Restricted Units on or before the end of the Restricted Period, all interest in such Restricted Units and any additional Restricted Units attributable to Dividend Equivalents shall be forfeited. The Participant has no right or interest in any Restricted Units that are forfeited.

7. Conditions to Issuance or Transfer of Shares. The issuance and transfer of Shares shall be subject to compliance by the Company and the Participant with all applicable laws, rules and regulations ("Applicable Laws") and also to such approvals by governmental agencies as may be deemed appropriate to comply with relevant securities laws and regulations. No Shares shall be issued or transferred unless and until any then applicable requirements of Applicable Laws and regulatory agencies have been fully complied with to the satisfaction of the Company and its counsel.

8. Tax Withholding. Participant shall be required to pay to the Company, and the Company shall have the right to deduct from any compensation paid to the Participant pursuant to the Plan, the amount of any required federal, state and local taxes, domestic or foreign, including payroll taxes, in respect of the Award and to take all such other action as the Committee deems necessary to satisfy all obligations for the payment of such withholding taxes. The Company shall have no obligation to issue any Shares to any Participant unless and until the Participant has made arrangements, satisfactory to the Company in its sole discretion, to satisfy the Participant's tax liability resulting from the vesting or settlement of the Vested Units. The amount of such withholding shall be determined by the Company. The Committee, in its sole discretion, may permit or require the Participant to satisfy any such tax withholding obligation by any of, or a combination of, the following means:

8.1 tendering a cash payment or check payable to the Company.

8.2 authorizing the Company to withhold an amount from any cash amounts otherwise due or to become due from the Company to the Participant.

8.3 authorizing the Company to withhold Shares from the Shares otherwise issuable to the Participant as a result of the vesting of the Restricted Units; provided, however, that no Shares shall be withheld with a Fair Market Value exceeding the maximum amount of tax required to be withheld by Applicable law.

8.4 delivering to the Company previously owned and unencumbered Shares having a then current Fair Market Value not exceeding the maximum amount of tax required to be withheld by Applicable Law.

9. Rights as Shareholder. Except as otherwise provided in the Agreement, the Participant shall not have any of the rights or privileges of a shareholder with respect to the Shares underlying the Restricted Units unless and until the Restricted Units vest and certificates representing such Shares (which may be in book-entry form) have been issued and recorded on the Company's records, and delivered to the Participant or to an escrow account for the Participant's benefit. After such issuance, recordation and delivery, Participant will have the rights of a shareholder of the Company with respect to such Shares, including without limitation, voting rights and the right to receipt of dividends and distributions on such Shares.

10. No Right to Continued Service. Neither the Plan nor this Agreement shall confer upon the Participant any right to serve as an employee or other service provider of the Company or a Subsidiary. Further, nothing in the Plan or this Agreement shall be construed to limit the discretion of the Company or a Subsidiary to terminate the services of the Participant at any time, with or without cause.

11. Adjustments. In the event of a change in capitalization described in Section 13 of the Plan prior to the end of the Restricted Period, other than a dividend described in Section 5 above, the Restricted Units shall be equitably adjusted or terminated in any manner contemplated by the Plan to reflect the effect of such event or change in the Company's capital structure in such a way as to preserve the value of the Award.

12. Required Participant Repayment/Reduction Provision. Notwithstanding anything in the Plan or this Agreement to the contrary, all or a portion of the Award made to the Participant under this Agreement is subject to being called for repayment to the Company or reduced in any situation required by law or specified by Company policy in effect at the time of the request for repayment or reduction is made. In any event, even if not required by law or Company policy, in any situation where the Board or a committee thereof determines that fraud, negligence, or intentional misconduct by the Participant was a contributing factor to the Company having to restate all or a portion of its financial statement(s), the Committee may request repayment or reduction. The Committee may determine whether the Company shall effect any such repayment or reduction: (i) by seeking repayment from the Participant, (ii) by reducing (subject to Applicable Law and the Plan's terms and conditions or any other applicable plan, program, or arrangement) the amount that would otherwise be awarded or payable to the Participant under the Award, the Plan or any other compensatory plan, program, or arrangement maintained by the Company, (iii) by withholding payment of future increases in compensation (including the payment of any discretionary bonus amount) or grants of compensatory awards that would otherwise have been made in accordance with the Company's otherwise applicable compensation practices, or (iv) by any combination of the foregoing. The determination regarding the Participant's conduct, and repayment or reduction under this provision shall be within the Committee's sole discretion and shall be final and binding on the Participant and the Company.

The Participant, in consideration of the grant of the Award, and by the Participant's execution of this Agreement, acknowledges the Participant's understanding and agreement to this provision, and hereby agrees to make and allow an immediate and complete repayment or reduction in accordance with this provision in the event of a call for repayment or other action by the Company or Committee to effect its terms with respect to the Participant, the Award and/or any other compensation described herein.

13. Company Policies. The Participant agrees that the Award will be subject to any applicable insider trading policies, retention policies and other policies that may be implemented by the Board, from time to time.

14. Participant Undertaking. The Participant agrees to take whatever additional actions and execute whatever additional documents the Company may in its reasonable judgment deem necessary or advisable in order to carry out or effect one or more of the obligations or restrictions imposed on the Participant pursuant to the terms of this Agreement. It is intended by the Company that the Plan and Shares covered by the Award are to be registered under the Securities Act of 1933, as amended, prior to the grant date; provided that in the event such registration is for any reason not effective for such Shares, the Participant agrees that all Shares acquired pursuant to the grant will be acquired for investment and will not be available for sale or tender to any third party.

15. Beneficiary. The Participant may designate a Beneficiary to receive any rights of the Participant which may become vested in the event of the Participant's death under procedures and in the form established by the Committee; and in the absence of such designation of a Beneficiary, any such rights shall be deemed to be transferred to the Participant's estate.

16. Notices. Any notice required to be delivered to the Company under this Agreement shall be in writing and addressed to the Senior Vice President-Administration and Chief Information Officer, or his successor in charge of compensation and benefits in Human Resources, of the Company at the Company's principal corporate offices. Any notice required to be delivered to the Participant under this Agreement shall be in writing and addressed to the Participant at the Participant's address as shown in the records of the Company. Either party may designate another address in writing (or by such other method approved by the Company) from time to time.

17. Incorporation of the Plan; Conflicts. The Restricted Units and the Shares issued to Participant hereunder are subject to the terms and conditions set forth in this Agreement and the Plan, which is incorporated herein by reference. In the event of any inconsistency between (1) the Plan and this Agreement, the Plan will control, or (2) the resolutions and records of the Board or Committee and this Agreement, the resolutions and records of the Board or Committee will control.

18. Successors and Assigns. The Company may assign any of its rights under this Agreement, and this Agreement will be binding upon and inure to the benefit of the Company's

successors and assigns. Subject to the restrictions on transfer set forth herein and the Plan, this Agreement will be binding upon and inure to the benefit of the heirs, legatees, legal representatives, successors and assigns of the parties hereto.

19. No Impact on Other Benefits. The Company does not intend for the value of the Award or any Vested Units to be included in the Participant's normal or expected compensation for purposes of calculating any severance, retirement, welfare, insurance or similar employee benefit; provided, however, that if there is any inconsistency between this Agreement and the terms of another benefit plan, the benefit plan document will control.

20. Discretionary Nature of Plan. The Plan is discretionary and may be amended, cancelled or terminated by the Board at any time, in its discretion. The grant of the Restricted Units in this Agreement does not create any contractual right or other right to receive any Restricted Units or other awards in the future. Future awards, if any, will be at the Committee's sole discretion. Any amendment, modification, or termination of the Plan shall not constitute a change or impairment of the terms and conditions of the Participant's employment with the Company.

21. Amendment. In accordance with the Plan, the Committee may amend or otherwise modify, suspend, discontinue or terminate this Agreement at any time, prospectively or retroactively.

22. Section 409A.

22.1 This Award and Agreement is intended to comply with Section 409A or an exemption thereunder and shall be construed and interpreted in a manner that is consistent with the requirements for avoiding additional taxes or penalties under Section 409A. Notwithstanding any other provision of the Agreement, any distributions or payments due hereunder may only be made upon an event and in a manner that complies with Section 409A or an applicable exemption. Any distributions or payments due hereunder upon a termination of employment shall only be made upon a "separation from service" as defined in Section 409A. The right to a series of installment payments under this Agreement shall be treated as a right to a series of separate payments. In no event may the Participant, directly or indirectly, designate the calendar year of settlement, distribution or payment.

22.2 If an Award is subject to Section 409A and Participant becomes entitled to settlement of the Award on account of a separation from service and is a "specified employee" within the meaning of Section 409A on the date of the separation from service, then to the extent necessary to prevent any accelerated or additional tax under Section 409A, such settlement will be delayed until the earlier of: (a) the date that is six months following the Participant's separation from service and (b) the Participant's death (the "Delayed Payment Date") and the accumulated amounts shall be distributed or paid in a lump sum payment on the Delayed Payment Date.

22.3 The Company does not represent that the Award or this Agreement complies with Section 409A and in no event shall the Company be liable for all or any portion of any taxes, penalties, interest or other expenses that may be incurred by the Participant on account of non-compliance with Section 409A.

22.4 To the extent that any provision of the Agreement would cause a conflict with the requirements of Section 409A, or would cause the administration of the Agreement to fail to satisfy Section 409A, such provision shall be deemed null and void to the extent permitted by Applicable Law.

23. Entire Agreement. The Plan and this Agreement (including any exhibit hereto) constitute the entire agreement of the parties and supersede in their entirety all prior undertakings and agreements of the Company and the Participant with respect to the subject matter hereof.

24. Severability. The invalidity or unenforceability of any provision of the Plan or this Agreement shall not affect the validity or enforceability of any other provision of the Plan or this Agreement, and each provision of the Plan and this Agreement shall be severable and enforceable to the extent permitted by law.

25. Governing Law. This Agreement will be construed and interpreted in accordance with the laws of the State of Oklahoma without regard to the conflict of laws provisions thereof.

26. Counterparts. This Agreement may be executed in one or more counterparts, including by way of electronic signature, subject to Applicable Law, each of which shall be deemed an original and all of which together will constitute one instrument.

27. Administration of Award; Acceptance. As a condition of receiving this Award, the Participant agrees that the Committee shall have full and final authority to construe and interpret the Plan and this Agreement, and to make all other decisions and determinations as may be required under the Plan or this Agreement as they may deem necessary or advisable for administration of the Plan or this Agreement, and that all such interpretations, decisions and determinations shall be final and binding on the Participant, the Company and all other interested persons. Any dispute regarding the interpretation of this Agreement shall be submitted by the Participant or the Company to the Committee for review. The resolution of such dispute by the Committee shall be final and binding on the Participant and the Company. Day-to-day authority and responsibility has been delegated to the Company's ONE Gas, Inc. Benefits Committee and its authorized representatives, and all actions taken thereby shall be entitled to the same deference as if taken by the Committee itself.

The Participant hereby acknowledges receipt of this Agreement and a copy of the Plan. Participant agrees to be bound by all of the provisions set forth in this Agreement and the Plan and acknowledges that there may be adverse tax consequences upon the vesting or settlement of the Restricted Units or disposition of the underlying Shares and that Participant has been advised to consult a tax advisor prior to such vesting, settlement

or disposition. Participant accepts the Award under the terms and conditions stated in this Agreement, subject to all terms and provisions of the Plan, by electronic acceptance of the grant.

ONE GAS, INC.

PERFORMANCE UNIT AWARD AGREEMENT

This Performance Unit Award Agreement (this "Agreement") is made and entered into as of February 20, 2023 (the "Grant Date") by and between ONE Gas, Inc., an Oklahoma corporation (the "Company") and the "Participant" named below.

Participant: %%FIRST_NAME_MIDDLE_NAME_LAST_NAME%-%

WHEREAS, the Company has adopted the ONE Gas, Inc. Amended and Restated Equity Compensation Plan (2018), as amended from time to time (the "Plan"), pursuant to which Performance Unit Awards may be granted; and

WHEREAS, the Executive Compensation Committee of the Board of Directors (the "Committee") has determined that it is in the best interests of the Company and its shareholders to grant the Performance Unit Award provided for herein.

NOW, THEREFORE, the parties hereto, intending to be legally bound, agree as follows:

1. <u>Grant of Performance Units</u>.

1.1 The Company hereby grants to the Participant an award consisting of the number of Performance Units specified below ("Performance Units" or the "Award") on the terms and conditions set forth in this Agreement and the Plan.

Number of Performance Units: %%TOTAL_SHARES_GRANTED,'999,999,999'%-%

The Performance Units are contingently awarded and will be earned if and only to the extent that the performance goal described on Exhibit A (the "Performance Goal") is met and will be vested and distributable only if other conditions in this Agreement are met. Each Performance Unit represents the right to receive one share of the Company's common stock ("Share") or, at the Company's option, an amount of cash as set forth in Section 6.2, in either case, at the times and subject to the conditions set forth herein. The number of Performance Units set forth above is equal to a target number of Shares that the Participant will earn for 100% achievement of the Performance Goal (the "Target Award"). Capitalized terms that are used but not defined herein have the meanings set forth in the Plan.

1.2 The Performance Units shall be credited to a separate account maintained for the Participant on the books and records of the Company (the "Account"). All amounts credited to the Account shall continue for all purposes to be part of the general assets of the Company.

1.3 For purposes of this Agreement, the term "Performance Period" shall be the period commencing on January 1, 2023 and ending on December 31, 2025.

2. Consideration. The Award is granted in consideration of the Participant's continued employment with the Company.

3. Vesting.

3.1 General. Except as provided in this Section 3, subject to Participant's continuous employment with the Company during the period beginning on the Grant Date and ending on February 14, 2026 (the "Vesting Date") and subject to the terms of this Agreement, the Participant shall vest on the Vesting Date in the number of Performance Units, if any, earned upon, and certified following, the attainment of the Performance Goal for the Performance Period. Any Performance Units that do not vest as of the Vesting Date shall be forfeited. Performance Units that vest pursuant to the terms of this Agreement, including Sections 3.2 and 3.3 below, are hereinafter referred to as "Vested Units. Unless and until the Performance Units have vested, Participant will have no right to receive any Shares subject thereto. Prior to the actual delivery of any Shares, the Award will represent an unsecured obligation of the Company, payable only from the Company's general assets.

3.2 Termination of Employment. If prior to the Vesting Date, the Participant ceases to be employed by the Company on account of the Participant's Retirement, Total Disability or death, the Participant will vest in a pro-rata portion of the Performance Units as of the Vesting Date if the Performance Goal and requirements of this Agreement are met as of such date. The pro-rata portion of the Performance Units that vest will be determined by multiplying (x) the maximum number of Performance Units in which the Participant could vest, based on the actual level at which the Performance Goal is attained and certified for the Performance Period, as if the Participant remained in the continuous employment of the Company until the Vesting Date, by (y) a fraction, which fraction shall be equal to the number of full calendar months which have elapsed since the Grant Date at the time of such termination of employment divided by the number of months in the Performance Period. If the Participant's employment with the Company terminates prior to the Vesting Date for any other reason, Participant shall immediately forfeit any and all Performance Units that have not vested or do not vest on or prior to the Participant's termination date and neither the Company nor any Subsidiary shall have any further obligations to the Participant under this Agreement. For purposes of this Agreement, employment with any Subsidiary of the Company shall be treated as employment with the Company. Likewise, a termination of employment shall not be deemed to occur by reason of a transfer of employment between the Company and any Subsidiary. For purposes of this Agreement:

(a) "Retirement" means a voluntary termination of employment of the Participant with the Company by the Participant if at the time of such termination of employment the Participant has both completed five (5) years of service with the Company and attained age fifty (50).

(b) "Total Disability" means that the Participant is permanently and totally disabled and unable to engage in any substantial gainful activity by reason of a medically determinable physical or mental impairment which can be expected to result in death, or which has lasted or can be expected to last for a continuous period of not less than twelve (12) months, and has established such disability to the extent and in the manner and form as may be required by the Committee.

3.3 Change in Control. If a Change in Control occurs prior to the Vesting Date and the Participant is employed by the Company at the time of the Change in Control, but subsequently terminates prior to the Vesting Date based on an involuntary termination (without cause) or a voluntary termination with "good reason" within 24 months of the Change in Control date, then the Participant's Performance Units will vest at the Target Award level on the date of such termination (the "Change in Control Vesting Date"). Good reason includes:

- Demotion or material reduction of authority or responsibility;
- Material reduction in base salary;
- Material reduction in annual incentive or LTI targets;
- Relocation of greater than 35 miles; or
- Failure of the successor company to assume the change-in-control plan.

Notwithstanding the foregoing, the provisions set forth in the Plan applicable to a Change in Control shall apply to the Award, and in the event of a Change in Control, the Committee, in its sole discretion and to the extent permitted by Section 409A, may take such actions as it deems appropriate pursuant to the Plan. For purposes of this Agreement, the term "Change in Control" shall have the same meaning as provided in the Plan unless the Award is or becomes subject to Section 409A, in which event "Change in Control" shall have the meaning provided in Section 409A and the related Treasury Regulations.

3.4 Certification. The Committee shall, within a reasonably practicable time following the end of the Performance Period, certify to the extent, if any, to which the Performance Goal has been achieved with respect to the Performance Period and the number of Performance Units, if any, earned upon attainment of the Performance Goal and subject to Section 3. Such certification shall be final, conclusive and binding on the Participant, and on all other persons, to the maximum extent permitted by law.

4. Transfer Restrictions.

4.1 Except as provided in Section 4.2, during the Performance Period and until such time as the Shares underlying the Vested Units have been issued, the Performance Units, related Shares or the rights relating thereto may not be sold, pledged, assigned, transferred or otherwise

disposed of by the Participant in any manner other than by will or by laws of descent and distribution. Except as provided in Section 4.2, any attempt to sell, pledge, assign, transfer or otherwise dispose of the Performance Units, related Shares or the rights relating thereto shall be wholly ineffective and, if any such attempt is made, the Performance Units, related Shares or the rights relating thereto will be forfeited by the Participant and all of the Participant's rights to such units or related Shares shall immediately terminate without any payment or consideration by the Company.

4.2 Notwithstanding the foregoing, the Participant may transfer any part or all of the Participant's rights in the Performance Units to members of the Participant's immediate family, or to one or more trusts for the benefit of such immediate family members, or partnerships in which such immediate family members are the only partners if the Participant does not receive any consideration for the transfer. In the event of any such transfer, Performance Units shall continue to be subject to the same terms and conditions otherwise applicable hereunder and under the Plan immediately prior to transfer, except that such rights shall not be further transferable by the transferee inter vivos, except for transfer back to the Participant. For any such transfer to be effective, the Participant must provide prior written notice thereof to the Committee and the Participant shall furnish to the Committee such information as it may request with respect to the transferee and the terms and conditions of any such transfer. For purposes of this Agreement, "immediate family" shall mean the Participant's spouse, children and grandchildren.

5. Dividend Equivalents. The Participant's Account shall be credited with an amount equal to all ordinary cash dividends ("Dividend Equivalents") that would have been paid to the Participant if one Share had been issued on the Grant Date for each Performance Unit granted to the Participant as set forth in this Agreement. The Dividend Equivalents credited to the Participant's Account will be deemed to be reinvested in additional Performance Units (or fractional units) and will be subject to the same terms and conditions as the Performance Units to which they are attributable and shall vest or be forfeited (if applicable) and settled at the same time as the Performance Units to which they are attributable. Such additional Performance Units shall also be credited with additional Dividend Equivalents as any further dividends are declared. No Dividend Equivalents shall be credited with respect to any Performance Units, which as of the record date, have either been settled or forfeited.

6. Time and Form of Payment with Respect to Vested Units.

6.1 Unless an election is made pursuant to Section 7 below and subject to Section 10 and Section 23.2 and subject to certification by the Committee that the Performance Goal has been achieved and other vesting conditions have been satisfied, the Participant will receive a distribution with respect to the Vested Units within 75 days following the earlier of (i) the Vesting Date (the "Distribution Date") or (ii) the Change in Control Vesting Date described in

Section 3.3. The Vested Units will be settled and distributed in Shares (either in book-entry form or otherwise) or, at the Company's option, paid in an amount of cash as set forth in Section 6.2. All distributions in Shares shall be in the form of whole Shares, and any fractional Share shall be distributed in cash in an amount equal to the value of such fractional Share determined based on the Fair Market Value of a Share on the Vesting Date or Change in Control Vesting Date, as applicable.

6.2 If the Company elects to settle the Participant's Vested Units in cash, the amount of cash payable with respect to each Vested Unit shall be equal to the Fair Market Value of a Share on the Vesting Date or Change in Control Vesting Date, as applicable.

6.3 To the extent that the Participant does not vest in any Performance Units on or before the Vesting Date, all interest in such Performance Units and any additional Performance Units attributable to Dividend Equivalents shall be forfeited. The Participant has no right or interest in any Performance Units that are forfeited.

7. Deferral Election for Officers.

7.1 If the Participant is an officer of the Company, the Participant may irrevocably elect to defer the Distribution Date of Performance Units, Shares and cash that the Participant becomes entitled to receive under this Agreement (the "Deferred Amounts") to a later date, by filing with the Committee, on or before the deferral election date (the "Election Deadline") described in Section 7.2 below, a signed written irrevocable election (the "Election") which shall be in the form substantially the same as attached hereto as Exhibit D, or as otherwise approved by the Committee.

7.2 Any such Election shall be filed with the Committee on or before the Election Deadline, which shall be June 30, 2025, the date that is six (6) months before the end of the Performance Period and shall become effective and irrevocable on such date provided that the Participant performs services for the Company continuously from the later of the beginning of the Performance Period or the date the Performance Goal was established through the Election Deadline. Notwithstanding the foregoing, in no event shall the Participant's Election become effective if any portion of the Deferred Amounts has become readily ascertainable (within the meaning of Section 409A) and is substantially certain to be paid the Participant as of the Election Deadline. To defer the Distribution Date, the Participant must elect to defer one-hundred percent (100%) of the Deferred Amounts. Subject to Section 23.2, the Deferred Amounts shall be distributed to Participant at the time and in the form set forth in the Election (the "Deferred Date"). Notwithstanding a Participant's Election pursuant to this Section 7, if a Change in Ownership or Control (within the meaning of Section 409A) occurs prior to the Deferred Date, the Deferred Amounts will be distributed to the Participant on the date of the Change in Ownership or Control.

7.3 This Section 7 shall be applicable solely to the Award and shall not apply to any other compensation payable to the Participant under the Plan or otherwise. The right to make a deferral election under this Section 7 is expressly limited to officers of the Company or any subset thereof as determined by the Committee from time to time. This Agreement shall not permit a subsequent election to delay or modify the form of payment unless authorized and agreed upon in writing by the Company and Participant and such subsequent election complies with Section 409A.

8. Conditions to Issuance or Transfer of Shares. The issuance and transfer of Shares shall be subject to compliance by the Company and the Participant with all applicable laws, rules and regulations ("Applicable Laws") and also to such approvals by governmental agencies as may be deemed appropriate to comply with relevant securities laws and regulations. No Shares shall be issued or transferred unless and until any then applicable requirements of Applicable Laws and regulatory agencies have been fully complied with to the satisfaction of the Company and its counsel.

9. Tax Withholding. Participant shall be required to pay to the Company, and the Company shall have the right to deduct from any compensation paid to the Participant pursuant to the Plan, the amount of any required federal, state and local taxes, domestic or foreign, including payroll taxes, in respect of the Award and to take all such other action as the Committee deems necessary to satisfy all obligations for the payment of such withholding taxes. The Company shall have no obligation to issue any Shares to any Participant unless and until the Participant has made arrangements, satisfactory to the Company in its sole discretion, to satisfy the Participant's tax liability resulting from the vesting or settlement of the Vested Units. The amount of such withholding shall be determined by the Company. The Committee, in its sole discretion, may permit or require the Participant to satisfy any such tax withholding obligation by any of, or a combination of, the following means:

9.1 tendering a cash payment or check payable to the Company.

9.2 authorizing the Company to withhold an amount from any cash amounts otherwise due or to become due from the Company to the Participant.

9.3 authorizing the Company to withhold Shares from the Shares otherwise issuable to the Participant as a result of the vesting of the Performance Units; provided, however, that no Shares shall be withheld with a Fair Market Value exceeding the maximum amount of tax required to be withheld by Applicable law.

9.4 delivering to the Company previously owned and unencumbered Shares having a then current Fair Market Value not exceeding the maximum amount of tax required to be withheld by Applicable Law.

10. Rights as Shareholder. Except as otherwise provided in the Agreement, the Participant shall not have any of the rights or privileges of a shareholder with respect to the Shares underlying the Performance Units unless and until the Performance Units vest and certificates representing such Shares (which may be in book-entry form) have been issued and recorded on the Company's records and delivered to the Participant or to an escrow account for the Participant's benefit. After such issuance, recordation and delivery, Participant will have the rights of a shareholder of the Company with respect to such Shares, including without limitation, voting rights and the right to receipt of dividends and distributions on such Shares.

11. No Right to Continued Service. Neither the Plan nor this Agreement shall confer upon the Participant any right to serve as an employee or other service provider of the Company or a Subsidiary. Further, nothing in the Plan or this Agreement shall be construed to limit the discretion of the Company or a Subsidiary to terminate the services of the Participant at any time, with or without cause.

12. Adjustments. In the event of a change in capitalization described in Section 13 of the Plan prior to the Vesting Date, other than a dividend described in Section 5 above, the Performance Units shall be equitably adjusted or terminated in any manner contemplated by the Plan to reflect the effect of such event or change in the Company's capital structure in such a way as to preserve the value of the Award.

13. Required Participant Repayment/Reduction Provision. Notwithstanding anything in the Plan or this Agreement to the contrary, all or a portion of the Award made to the Participant under this Agreement is subject to being called for repayment to the Company or reduced in any situation required by law or as specified by Company policy in effect at the time of the request for repayment or reduction is made. In any event, even if not required by law or Company policy, in any situation where the Board or a committee thereof determines that fraud, negligence, or intentional misconduct by the Participant was a contributing factor to the Company having to restate all or a portion of its financial statement(s), the Committee may request repayment or reduction. The Committee may determine whether the Company shall effect any such repayment or reduction: (i) by seeking repayment from the Participant, (ii) by reducing (subject to Applicable Law and the Plan's terms and conditions or any other applicable plan, program, or arrangement) the amount that would otherwise be awarded or payable to the Participant under the Award, the Plan or any other compensatory plan, program, or arrangement maintained by the Company, (iii) by withholding payment of future increases in compensation (including the payment of any discretionary bonus amount) or grants of compensatory awards that would otherwise have been made in accordance with the Company's otherwise applicable compensation practices, or (iv) by any combination of the foregoing. The determination regarding the Participant's conduct, and repayment or reduction under this provision shall be within the Committee's sole discretion and shall be final and binding on the Participant and the Company. The Participant, in consideration of the grant of the Award, and by the Participant's

execution of this Agreement, acknowledges the Participant's understanding and agreement to this provision, and hereby agrees to make and allow an immediate and complete repayment or reduction in accordance with this provision in the event of a call for repayment or other action by the Company or Committee to effect its terms with respect to the Participant, the Award and/or any other compensation described herein.

14. Company Policies. The Participant agrees that the Award will be subject to any applicable insider trading policies, retention policies and other policies that may be implemented by the Board, from time to time.

15. Participant Undertaking. The Participant agrees to take whatever additional actions and execute whatever additional documents the Company may in its reasonable judgment deem necessary or advisable in order to carry out or effect one or more of the obligations or restrictions imposed on the Participant pursuant to the terms of this Agreement. It is intended by the Company that the Plan and Shares covered by the Award are to be registered under the Securities Act of 1933, as amended, prior to the grant date; provided that in the event such registration is for any reason not effective for such Shares, the Participant agrees that all Shares acquired pursuant to the grant will be acquired for investment and will not be available for sale or tender to any third party.

16. Beneficiary. The Participant may designate a Beneficiary to receive any rights of the Participant which may become vested in the event of the Participant's death under procedures and in the form established by the Committee; and in the absence of such designation of a Beneficiary, any such rights shall be deemed to be transferred to the Participant's estate.

17. Notices. Any notice required to be delivered to the Company under this Agreement shall be in writing and addressed to the Senior Vice President-Administration and Chief Information Officer, or his successor in charge of compensation and benefits in Human Resources, of the Company at the Company's principal corporate offices. Any notice required to be delivered to the Participant under this Agreement shall be in writing and addressed to the Participant at the Participant's address as shown in the records of the Company. Either party may designate another address in writing (or by such other method approved by the Company) from time to time.

18. Incorporation of the Plan; Conflicts. The Performance Units and the Shares issued to Participant hereunder are subject to the terms and conditions set forth in this Agreement and the Plan, which is incorporated herein by reference. In the event of any inconsistency between (1) the Plan and this Agreement, the Plan will control, or (2) the resolutions and records of the Board or Committee and this Agreement, the resolutions and records of the Board or Committee will control.

19. Successors and Assigns. The Company may assign any of its rights under this Agreement, and this Agreement will be binding upon and inure to the benefit of the Company's

successors and assigns. Subject to the restrictions on transfer set forth herein and the Plan, this Agreement will be binding upon and inure to the benefit of the heirs, legatees, legal representatives, successors and assigns of the parties hereto.

20. No Impact on Other Benefits. The Company does not intend for the value of the Award or any Vested Units to be included in the Participant's normal or expected compensation for purposes of calculating any severance, retirement, welfare, insurance or similar employee benefit; provided, however, that if there is any inconsistency between this Agreement and the terms of another benefit plan, the benefit plan document will control.

21. Discretionary Nature of Plan. The Plan is discretionary and may be amended, cancelled or terminated by the Board at any time, in its discretion. The grant of the Performance Units in this Agreement does not create any contractual right or other right to receive any Performance Units or other awards in the future. Future awards, if any, will be at the Committee's sole discretion. Any amendment, modification, or termination of the Plan shall not constitute a change or impairment of the terms and conditions of the Participant's employment with the Company.

22. Amendment. In accordance with the Plan, the Committee may amend or otherwise modify, suspend, discontinue or terminate this Agreement at any time, prospectively or retroactively.

23. Section 409A.

23.1 This Award and Agreement is intended to comply with Section 409A or an exemption thereunder and shall be construed and interpreted in a manner that is consistent with the requirements for avoiding additional taxes or penalties under Section 409A. Notwithstanding any other provision of the Agreement, any distributions or payments due hereunder may only be made upon an event and in a manner that complies with Section 409A or an applicable exemption. Any distributions or payments due hereunder upon a termination of employment shall only be made upon a "separation from service" as defined in Section 409A. The right to a series of installment payments under this Agreement shall be treated as a right to a series of separate payments. Except as provided in Section 7, in no event may the Participant, directly or indirectly, designate the calendar year of settlement, distribution or payment.

23.2 If an Award is subject to Section 409A and Participant becomes entitled to settlement of the Award on account of a separation from service and is a "specified employee" within the meaning of Section 409A on the date of the separation from service, then to the extent necessary to prevent any accelerated or additional tax under Section 409A, such settlement will be delayed until the earlier of: (a) the date that is six months following the Participant's separation from service and (b) the Participant's death (the "Delayed Payment Date") and the

accumulated amounts shall be distributed or paid in a lump sum payment on the Delayed Payment Date.

23.3 The Company does not represent that the Award or this Agreement complies with Section 409A and in no event shall the Company be liable for all or any portion of any taxes, penalties, interest or other expenses that may be incurred by the Participant on account of non-compliance with Section 409A.

23.4 To the extent that any provision of the Agreement would cause a conflict with the requirements of Section 409A, or would cause the administration of the Agreement to fail to satisfy Section 409A, such provision shall be deemed null and void to the extent permitted by Applicable Law.

24. Entire Agreement. The Plan and this Agreement (including any exhibit hereto) constitute the entire agreement of the parties and supersede in their entirety all prior undertakings and agreements of the Company and the Participant with respect to the subject matter hereof.

25. Severability. The invalidity or unenforceability of any provision of the Plan or this Agreement shall not affect the validity or enforceability of any other provision of the Plan or this Agreement, and each provision of the Plan and this Agreement shall be severable and enforceable to the extent permitted by law.

26. Governing Law. This Agreement will be construed and interpreted in accordance with the laws of the State of Oklahoma without regard to the conflict of laws provisions thereof.

27. Counterparts. This Agreement may be executed in one or more counterparts, including by way of electronic signature, subject to Applicable Law, each of which shall be deemed an original and all of which together will constitute one instrument.

28. Administration of Award; Acceptance. As a condition of receiving this Award, the Participant agrees that the Committee shall have full and final authority to construe and interpret the Plan and this Agreement, and to make all other decisions and determinations as may be required under the Plan or this Agreement as they may deem necessary or advisable for administration of the Plan or this Agreement, and that all such interpretations, decisions and determinations shall be final and binding on the Participant, the Company and all other interested persons. Any dispute regarding the interpretation of this Agreement shall be submitted by the Participant or the Company to the Committee for review. The resolution of such dispute by the Committee shall be final and binding on the Participant and the Company. Day-to-day authority and responsibility has been delegated to the Company's ONE Gas, Inc. Benefits Committee and its authorized representatives, and all actions taken thereby shall be entitled to the same deference as if taken by the Committee itself.

The Participant hereby acknowledges receipt of this Agreement and a copy of the Plan. Participant agrees to be bound by all of the provisions set forth in this Agreement and the Plan and acknowledges that there may be adverse tax consequences upon the vesting or settlement of the Performance Units or disposition of the underlying Shares and that Participant has been advised to consult a tax advisor prior to such vesting, settlement or disposition. Participant accepts the Award under the terms and conditions stated in this Agreement, subject to all terms and provisions of the Plan, by electronic acceptance of the grant.

Exhibit A
Performance Unit Performance Goal
2023-2025 Performance Period

Subject to the terms of the Agreement, Participant shall vest in a percentage of the Target Award (including any Dividend Equivalents) on the Vesting Date, based on the Company's ranking for Total Stockholder Return ("TSR") for the Performance Period against the ONE Gas Peer Group listed in Exhibit C, all as determined by the Committee in its sole discretion. TSR for the Performance Period is the measure of the stock price appreciation plus any dividends paid during the Performance Period, expressed as a percentage. The TSR beginning stock price for the Performance Period is the average of the closing stock price for the 20 trading days immediately preceding the beginning of the Performance Period. The TSR ending stock price for the Performance Period is the average of the closing stock price for the 20 trading days leading up to and including the last day of the Performance Period. Exhibit B provides an illustration of a Hypothetical Performance Period calculation.

The number of Performance Units earned at the time of vesting is based on the Company's TSR percentile rank for the Performance Period as set forth in the following chart. If the actual TSR percentile rank falls between the stated percentile ranks set forth in the chart, the payout percentage is interpolated between the percentile rank above and below the actual percentile rank, except that no Performance Units are earned if ONE Gas's TSR ranking at the end of the Performance Period is below the 25th percentile.

Percentile Rank	Payout (as a % of Target)
90th percentile and above	200%
75th percentile	150%
50th percentile	100%
25th percentile	50%
Below the 25th percentile	0%

Exhibit B
Illustration of Hypothetical 2023-2025 Performance Period
Performance Unit Award Calculation

Illustration assumes 500 Performance Units Granted in February 2023

Total Stockholder Return (“TSR”) vs. ONE Gas Peer Group
Hypothetical ONE Gas TSR Ranking = 40th percentile A 40th percentile TSR ranking earns 80% of Performance Units granted (i.e., 500 units) as interpolated between 50% and 100% from Exhibit A (see chart above) 400 Performance Units earned*

Total Performance Units Earned
400 Performance Units 400* Performance Units earned out of 500 units granted = 80% “earn-out” [80% of 500 shares paid and distributed in the form of Shares]

*In addition, applicable Dividend Equivalents will be added with an 80% “earn-out”.

Exhibit C

2023-2025 ONE GAS TSR Peer Group

Company Name	Sym
Alliant Energy Corporation	LNT
Atmos Energy Corporation	ATO
Avista Corporation	AVA
Black Hills Corporation	BKH
CenterPoint Energy, Inc.	CNP
Chesapeake Utilities Corporation	CPK
CMS Energy Corporation	CMS
New Jersey Resources Corporation	NJR
NiSource Inc.	NI
Northwest Natural Holding Company	NWN
NorthWestern Corporation	NWE
Southwest Gas Holdings, Inc.	SWX
Spire Inc.	SR

In the event that any of the Peer Group companies are not available for performance comparison either by going out of business, being sold, being merged into another company or any other reason, then that company will be dropped from the list and the performance comparison will be made with the remaining Peer Group companies.

Exhibit D

ONE Gas, Inc.
Amended and Restated Equity Compensation Plan (2018)
Performance Unit Deferral Election

INSTRUCTIONS: This Deferral Election must be completed and returned to the plan administrator at ONE Gas, Inc. no later than June 30, 2025 (the "Election Deadline"). This election becomes irrevocable as of the Election Deadline; provided, however, this election shall only become effective to the extent permitted by Section 409A.

This Election is made by the undersigned Participant pursuant to the terms of the ONE Gas, Inc. Amended and Restated Equity Compensation Plan (2018), as amended from time to time (the "Plan") and that certain Performance Unit Award Agreement issued to me under the Plan on the 20th day of February, 2023 (the "Agreement"). Capitalized terms that are used but not defined herein have the meanings set forth in the Agreement.

1. <u>Irrevocable Elections as to the Time and Form of Payment</u>

I hereby irrevocably elect to defer the payment and my receipt of all Performance Units, Shares and cash that I may become entitled to receive pursuant to the Agreement (the "Deferred Amounts") from the regularly scheduled time of payment set forth in Section 6 of the Agreement until a later date as follows:

A. Specified Time of Payment Election (Put initials by your choice)

___ I elect to have the Deferred Amounts deferred and paid to me on the later of (i) the date of my separation from service as an employee of the Company, or (ii) [________, 20__] in the form specified below.

___ I elect to have the Deferred Amounts deferred and paid to me on the date of my separation from service as an employee of the Company in the form specified below.

B. Form of Payment Election (Put initials by your choice)

___ I elect to receive the Deferred Amounts in a single lump sum payment.

____ I elect to receive the Deferred Amounts in ______ (specify 2, 3, 4 or 5) equal annual installments commencing on the Specified Time of Payment that I have elected in Part A above, until fully paid. The number of Shares or cash received in each installment will equal the number and amount, respectively, that have not been paid as of the date immediately preceding the installment payment date, divided by the number of installments remaining to be paid as of the date immediately preceding the installment payment date. The resulting number shall

be rounded down to the next whole number, except that the final installment shall be rounded up to the next whole number.

C. Election in the Event of Death (Put initials by your choice)

___ In the event of my death prior to, or after, the Specified Time of Payment that I have elected above, I elect to have my named beneficiaries (or my estate, if I do not have any designated beneficiaries) receive payment and transfer of the Deferred Amounts in a single lump sum within 60 days following my death.

___ In the event of my death prior to, or after, the Specified Time of Payment that I have elected above, I elect to have my named beneficiaries (or my estate, if I do not have any designated beneficiaries) receive payment and transfer of the Deferred Amounts in ______ (specify 2, 3, 4 or 5) equal annual installments commencing within 60 days following my death, until fully paid. The number of Shares or cash received in each installment will equal the number and amount, respectively, that have not been paid as of the date immediately preceding the installment payment date, divided by the number of installments remaining to be paid as of the same date. The resulting number shall be rounded down to the next whole number, except that the final installment shall be rounded up to the next whole number.

D. Change in Ownership or Control (Mandatory Distribution)

Notwithstanding the above elections, if a Change in Ownership or Control (within the meaning of Section 409A) occurs prior to the full distribution of the Deferred Amounts, all Deferred Amounts that have not been paid and transferred will be paid and transferred on the date of the Change in Ownership or Control. In the event Shares no longer exist at the time of payment and transfer, each of the deferred Performance Units shall be converted in a manner that is consistent with the manner in which Shares held by shareholders of the Company were treated with respect to the Change in Ownership or Control.

2. Additional Terms

A. Unforeseeable Emergency. You may request an accelerated payment of all or a portion of the Deferred Amounts if you experience an Unforeseeable Emergency (as defined in the Plan), subject to the requirements set forth in Plan Section 11.5. If approved, payment shall be made in a single lump sum within 90 days after the approval date.

B. Specified Employee. If you become entitled to a distribution on account of a separation from service and you are "specified employee" (within the meaning of Section 409A) on the date of your separation from service, payment of all or a portion of your Deferred Amounts may be delayed in accordance with Plan Section 11.4.

C. Re-deferrals and Changing the Form of Payment. You may, at the Committee's discretion, be permitted to make a re-deferral election with respect to the amounts deferred hereunder in accordance with Plan Section 11.3.

D. Withholding. You will be required to satisfy any tax withholding obligations relating to the Deferred Amounts, and delivery of the Shares or cash will be conditional upon your satisfaction of such obligations.

3. Acknowledgment

By executing this Election, I acknowledge that:

A. I have read the terms of the Plan, the Agreement and this Election and agree to all the terms and conditions.

B. I understand that any amounts that I defer hereunder are unfunded and unsecured and subject to the claims of the Company's creditors in the event of the Company's insolvency.

C. I understand that the Plan, the Agreement and this Election are intended to comply with Section 409A and that they will be interpreted accordingly. However, I understand that the Company will have no liability with respect to any failure to comply with Section 409A.

D. I understand that this Election will become irrevocable as of the Election Deadline.

E. I have consulted with my own tax advisor regarding the tax consequences of participating in the Plan and making this election.

I hereby make this election as of this ___ day of ____, 20__.

____
Participant Signature

____
Print Participant's Name

____
Employee ID Number

Copy received this ____ day of ________, 20__,

____
For the Committee

SUBSIDIARIES OF ONE Gas, Inc.

1. ONE Gas Properties, L.L.C., an Oklahoma limited liability company.
2. Utility Insurance Company, an Oklahoma company.
3. Kansas Gas Service Securitization I, L.L.C., a Delaware limited liability company.

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (Nos. 333-236623 and 333-236658) and Form S-8 (Nos. 333-226394, 333-205099, 333-193690, and 333-256556) of ONE Gas, Inc. of our report dated February 23, 2023, relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers, LLP

Tulsa, Oklahoma
February 23, 2023

Certification

I, Robert S. McAnnally, certify that:

I have reviewed this annual report on Form 10-K of ONE Gas, Inc.;

Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors:

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2023

/s/ Robert S. McAnnally
Robert S. McAnnally
Chief Executive Officer

Certification

I, Caron A. Lawhorn, certify that:

I have reviewed this annual report on Form 10-K of ONE Gas, Inc.;

Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors:

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2023

/s/ Caron A. Lawhorn
Caron A. Lawhorn
Chief Financial Officer

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report on Form 10-K of ONE Gas, Inc. (the “Registrant”) for the period ending December 31, 2022, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Robert S. McAnnally, Chief Executive Officer of the Registrant, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition of the Registrant and results of operations of the Registrant.

/s/ Robert S. McAnnally
Robert S. McAnnally
Chief Executive Officer

February 23, 2023

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to ONE Gas, Inc. and will be retained by ONE Gas, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of ONE Gas, Inc. (the "Registrant") for the period ending December 31, 2022, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Caron A. Lawhorn, Chief Financial Officer of the Registrant, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and the results of operations of the Registrant.

/s/ Caron A. Lawhorn
Caron A. Lawhorn
Chief Financial Officer

February 23, 2023

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to ONE Gas, Inc. and will be retained by ONE Gas, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Delivering essential energy

Spire Inc.
2022 Form 10-K

2022 highlights

Fiscal years ended September 30	2022	2021	2020
Earnings and dividends (millions, except per share amounts)			
Net income	**$ 220.8**	$ 271.7	$ 88.6
Diluted earnings per share of common stock	**$ 3.95**	$ 4.96	$ 1.44
Net economic earnings*	**$ 216.3**	$ 266.3	$ 207.8
Net economic earnings per share of common stock*	**$ 3.86**	$ 4.86	$ 3.76
Dividends declared per share of common stock	**$ 2.74**	$ 2.60	$ 2.49
Operating revenues (millions)			
Gas Utility	**$ 1,945.6**	$ 2,118.2	$ 1,751.8
Gas Marketing and other	**252.9**	117.3	103.6
Total operating revenues	**$ 2,198.5**	$ 2,235.5	$ 1,855.4
Utility sales and customers			
Gas Utility volume sold and transported (millions of Ccf)	**3,175.0**	3,247.7	3,233.1
Customers (thousands)	**1,732.7**	1,725.9	1,713.2
Shareholders			
Common shareholders of record, end of period	**2,650**	2,771	2,897
Employees			
Total employees, end of period	**3,584**	3,710	3,583

*For further discussion of these non-GAAP financial measures, see pages 31-32 of our Form 10-K.

Profile

At Spire, we believe energy exists to help make people's lives better. It's a simple idea, but one that's at the heart of our company. Every day we serve 1.7 million homes and businesses, making us the fifth largest publicly traded natural gas company in the country. We help people fuel their daily lives through our gas utilities serving Alabama, Mississippi and Missouri.

Our natural gas-related businesses include Spire Marketing, a Houston-based provider of natural gas marketing and related services to a diverse customer base primarily in the central and southern U.S.; Spire STL Pipeline, a 65-mile pipeline that delivers economical shale gas from the Marcellus and Utica producing regions to our customers in eastern Missouri, while enhancing the resiliency and diversity of our supply; and Spire Storage, a Wyoming-based provider of natural gas storage services to customers in the western U.S.

We are transforming our business and pursuing growth through growing organically, investing in infrastructure and advancing through innovation. Learn more at SpireEnergy.com.

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 or 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended September 30, 2022

or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 or 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File Number	Name of Registrant, Address of Principal Executive Offices and Telephone Number	State of Incorporation	I.R.S. Employer Identification Number
1-16681	**Spire Inc.** 700 Market Street St. Louis, MO 63101 314-342-0500	Missouri	74-2976504
1-1822	**Spire Missouri Inc.** 700 Market Street St. Louis, MO 63101 314-342-0500	Missouri	43-0368139
2-38960	**Spire Alabama Inc.** 605 Richard Arrington Blvd N Birmingham, AL 35203 205-326-8100	Alabama	63-0022000

Securities registered pursuant to Section 12(b) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") (only applicable to Spire Inc.):

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock $1.00 par value	SR	New York Stock Exchange LLC
Depositary Shares, each representing a 1/1,000th interest in a share of 5.90% Series A Cumulative Redeemable Perpetual Preferred Stock, par value $25.00 per share	SR.PRA	New York Stock Exchange LLC

Securities registered pursuant to Section 12(g) of the Exchange Act: None

Indicate by check mark whether each registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933, as amended.

Spire Inc.	Yes ☒	No ☐
Spire Missouri Inc.	Yes ☐	No ☒
Spire Alabama Inc.	Yes ☐	No ☒

Indicate by check mark if each registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.

Spire Inc.	Yes ☐	No ☒
Spire Missouri Inc.	Yes ☐	No ☒
Spire Alabama Inc.	Yes ☐	No ☒

Indicate by check mark whether each registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Spire Inc.	Yes ☒	No ☐
Spire Missouri Inc.	Yes ☒	No ☐
Spire Alabama Inc.	Yes ☒	No ☐

Indicate by check mark whether each registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

Spire Inc.	Yes ☒	No ☐
Spire Missouri Inc.	Yes ☒	No ☐
Spire Alabama Inc.	Yes ☒	No ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

	Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company	Emerging growth company
Spire Inc.	X				
Spire Missouri Inc.			X		
Spire Alabama Inc.			X		

If an emerging growth company, indicate by check mark if each registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Spire Inc.	☐
Spire Missouri Inc.	☐
Spire Alabama Inc.	☐

Indicate by check mark whether each registrant has filed a report on and attestation to its management’s assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report.

Spire Inc.	☒
Spire Missouri Inc.	☐
Spire Alabama Inc.	☐

Indicate by check mark whether each registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Spire Inc.	Yes ☐	No ☒
Spire Missouri Inc.	Yes ☐	No ☒
Spire Alabama Inc.	Yes ☐	No ☒

The aggregate market value of the common equity held by non-affiliates of Spire Inc. amounted to $3,627,663,025 as of March 31, 2022. All of Spire Missouri Inc.’s and Spire Alabama Inc.’s equity securities are owned by Spire Inc., their parent company and a reporting company under the Exchange Act.

The number of shares outstanding of each registrant’s common stock as of November 11, 2022, was as follows:

Spire Inc.	Common Stock, par value $1.00 per share	52,499,844
Spire Missouri Inc.	Common Stock, par value $1.00 per share (all owned by Spire Inc.)	25,325
Spire Alabama Inc.	Common Stock, par value $0.01 per share (all owned by Spire Inc.)	1,972,052

This combined Form 10-K represents separate filings by Spire Inc., Spire Missouri Inc., and Spire Alabama Inc. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Each registrant makes no representation as to information relating to the other registrants, except that information relating to Spire Missouri Inc. and Spire Alabama Inc. is also attributed to Spire Inc.

Spire Missouri Inc. and Spire Alabama Inc. meet the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instructions I(2) to Form 10-K.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of proxy statement for Spire Inc. to be filed on or about December 14, 2022 — Part III.

Certain exhibits as indicated in Part IV.

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GLOSSARY OF KEY TERMS AND ABBREVIATIONS

AOCI	Accumulated other comprehensive income or loss
APSC	Alabama Public Service Commission
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
CCF	A gas measurement which represents a unit of volume equal to one hundred cubic feet
CCM	Cost Control Measure
Company	Spire and its subsidiaries unless the context suggests otherwise
COVID-19	Coronavirus disease 2019
EPS	Earnings per share
ESR	Enhanced Stability Reserve
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States of America
Gas Marketing	Segment including Spire Marketing, which provides natural gas marketing services
Gas Utility	Segment including the operations of the Utilities
GSA	Gas Supply Adjustment
ICE	Intercontinental Exchange
ISRS	Infrastructure System Replacement Surcharge
MMBtu	Million British thermal units
MoPSC	Missouri Public Service Commission
MSPSC	Mississippi Public Service Commission
NYMEX	New York Mercantile Exchange, Inc.
NYSE	New York Stock Exchange
O&M	Operation and maintenance expense
OCI	Other comprehensive income or loss
OFO	Operational Flow Order
PGA	Purchased Gas Adjustment
RSE	Rate Stabilization and Equalization
SEC	U.S. Securities and Exchange Commission
Spire	Spire Inc.
Spire Alabama	Spire Alabama Inc.
Spire EnergySouth	Spire EnergySouth Inc., parent of Spire Gulf and Spire Mississippi
Spire Gulf	Spire Gulf Inc.
Spire Marketing	Spire Marketing Inc.
Spire Mississippi	Spire Mississippi Inc.
Spire Missouri	Spire Missouri Inc.
Spire STL Pipeline	Spire STL Pipeline LLC, or the 65-mile FERC-regulated pipeline it constructed and operates to deliver natural gas into eastern Missouri
Spire Storage	The physical natural gas storage operations of Spire Storage West LLC
U.S.	United States
Utilities	Spire Missouri, Spire Alabama and the subsidiaries of Spire EnergySouth

PART I

FORWARD-LOOKING STATEMENTS

Certain matters discussed in this report, excluding historical information, include forward-looking statements. Certain words, such as “may,” “anticipate,” “believe,” “estimate,” “expect,” “intend,” “plan,” “seek,” “target,” and similar words and expressions identify forward-looking statements that involve uncertainties and risks. Future developments may not be in accordance with our current expectations or beliefs and the effect of future developments may not be those anticipated. Among the factors that may cause results or outcomes to differ materially from those contemplated in any forward-looking statement are:

- Weather conditions and catastrophic events, particularly severe weather in U.S. natural gas producing areas;
- Volatility in gas prices, particularly sudden and sustained changes in natural gas prices, including the related impact on margin deposits associated with the use of natural gas derivative instruments, and the impact on our competitive position in relation to suppliers of alternative heating sources, such as electricity;
- Changes in gas supply and pipeline availability, including as a result of decisions by natural gas producers to reduce production or shut in producing natural gas wells and expiration or termination of existing supply and transportation arrangements that are not replaced with contracts with similar terms and pricing (including as a result of a failure of the Spire STL Pipeline to secure permanent authorization from the FERC), as well as other changes that impact supply for and access to the markets in which our subsidiaries transact business;
- Acquisitions may not achieve their intended results;
- Legislative, regulatory and judicial mandates and decisions, some of which may be retroactive, including those affecting:
    - allowed rates of return and recovery of prudent costs,
    - incentive regulation,
    - industry structure,
    - purchased gas adjustment provisions,
    - rate design structure and implementation,
    - capital structures established for rate-setting purposes,
    - regulatory assets,
    - non-regulated and affiliate transactions,
    - franchise renewals,
    - authorization to operate facilities,
    - environmental or safety matters, including the potential impact of legislative and regulatory actions related to climate change and pipeline safety and security,
    - taxes,
    - pension and other postretirement benefit liabilities and funding obligations, or
    - accounting standards;
- The results of litigation;
- The availability of and access to, in general, funds to meet our debt obligations prior to or when they become due and to fund our operations and necessary capital expenditures, either through (i) cash on hand, (ii) operating cash flow, or (iii) access to the capital markets;
- Retention of, ability to attract, ability to collect from, and conservation efforts of, customers;
- Our ability to comply with all covenants in our indentures and credit facilities any violations of which, if not cured in a timely manner, could trigger a default of our obligations;
- Energy commodity market conditions;
- Discovery of material weakness in internal controls;
- The disruption, failure or malfunction of our operational and information technology systems, including due to cyberattacks; and
- Employee workforce issues, including but not limited to labor disputes, the inability to attract and retain key talent, and future wage and employee benefit costs, including costs resulting from changes in discount rates and returns on benefit plan assets.

Readers are urged to consider the risks, uncertainties, and other factors that could affect our business as described in this report. All forward-looking statements made in this report rely upon the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. We do not, by including this statement, assume any obligation to review or revise any particular forward-looking statement in light of future events.

Item 1. Business

OVERVIEW

Spire Inc. ("Spire") was formed in 2000 and is the holding company for Spire Missouri Inc. ("Spire Missouri"), Spire Alabama Inc. ("Spire Alabama"), other gas utilities, and gas-related businesses. Spire Missouri was formed in 1857 and Spire Alabama was formed in 1948 by the merger of two gas companies. Spire is committed to transforming its business and pursuing growth through growing organically, investing in infrastructure, and advancing through innovation. The Company has two key business segments: Gas Utility and Gas Marketing.

The Gas Utility segment includes the regulated operations of Spire Missouri, Spire Alabama, Spire Gulf Inc. ("Spire Gulf") and Spire Mississippi Inc. ("Spire Mississippi") (collectively, the "Utilities"). The business of the Utilities is subject to seasonal fluctuations with the peak period occurring in the winter heating season, typically November through April of each fiscal year. Spire Missouri is a public utility engaged in the purchase, retail distribution and sale of natural gas, with primary offices located in St. Louis, Missouri. Spire Missouri is the largest natural gas distribution utility system in Missouri, serving approximately 1.2 million residential, commercial and industrial customers in St. Louis, Kansas City, and other areas in Missouri. Spire Alabama is a public utility engaged in the purchase, retail distribution and sale of natural gas principally in central and northern Alabama, serving more than 0.4 million residential, commercial and industrial customers with primary offices located in Birmingham, Alabama. Spire Gulf and Spire Mississippi are utilities engaged in the purchase, retail distribution and sale of natural gas to 0.1 million customers in the Mobile, Alabama area and south-central Mississippi.

The Gas Marketing segment includes Spire Marketing Inc. ("Spire Marketing"), a wholly owned subsidiary providing natural gas marketing services.

As of September 30, 2022, Spire had 3,584 employees, including 2,347 for Spire Missouri and 1,009 for Spire Alabama. We believe that:

1. the safety and well-being of our employees is one of our most important responsibilities,
2. the development, education and advancement of employees is key to our sustainability, and
3. embracing an inclusive workforce full of diverse backgrounds and perspectives drives innovation.

We continue to implement processes, procedures and programs that have helped us reduce our employee injury rate for the eighth fiscal year in a row, marking a 21% year-over-year improvement and an overall improvement of 67% since fiscal year 2015. We offer incentives for weight management and gym membership, as well as employee assistance programs to provide counseling services and emotional support, and we have a formalized comprehensive well-being program that focuses on the physical, emotional, social and financial health of every employee.

All employees have access to developmental assessments, customized training, specialized degree programs, and partnerships with best-in-class organizations related to industry courses, leadership and management workshops and computer application development seminars. In addition, all employees are eligible for up to $6,000 per year in tuition assistance and have access to the Spire Learning Center, our robust internal learning management system. In their first year, construction and maintenance employees and service employees receive 160–200 hours of technical and safety training. Field operations employees average 40 hours annually of training and Operator Qualification instruction.

We regularly review and adjust our affirmative action plans based on placement and utilization rates, and we strive to create an even more diverse and inclusive work environment by committing to and achieving the goals of the CEO Action for Diversity & Inclusion Pledge. Our Human Rights Policy demonstrates that Spire understands its universal responsibility to respect human rights and provides the basis for publicly affirming our values and embedding the responsibility into Spire's operations and the way we do business.

Spire uses its website, SpireEnergy.com, as its primary channel for distribution of important information including news releases, analyst presentations and financial information. The information Spire, Spire Missouri and Spire Alabama file or furnish to the United States (U.S.) Securities and Exchange Commission (SEC), including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and their amendments, and proxy statements are available free of charge under "Filings & reports" in the Investors section of Spire's website, SpireEnergy.com, as soon as reasonably practical after the information is filed with or furnished to the SEC. Information contained on Spire's website is not incorporated by reference in this report. The SEC also maintains a website that contains Spire's SEC filings (sec.gov).

GAS UTILITY

Natural Gas Supply

The Utilities' fundamental gas supply strategy is to meet the two-fold objective of 1) ensuring a dependable gas supply is available for delivery when needed and 2) insofar as is compatible with that dependability, purchasing gas that is economically priced. In structuring their natural gas supply portfolio, the Utilities focus on natural gas assets that are strategically positioned to meet the Utilities' primary objectives.

Spire Missouri focuses its gas supply portfolio around a number of large natural gas suppliers with equity ownership or control of assets strategically situated to complement its regionally diverse firm transportation arrangements. Spire Missouri utilizes Midcontinent, Gulf Coast, Northeast, and Rocky Mountain gas sources to provide a level of supply diversity that facilitates the optimization of pricing differentials as well as protecting against the potential of regional supply disruptions. Further, Spire STL Pipeline LLC ("Spire STL Pipeline"), a wholly owned subsidiary of Spire, may deliver up to 400,000 million British thermal units (MMBtu) per day of natural gas into eastern Missouri, of which Spire Missouri is the foundation shipper with a contractual commitment of 350,000 MMBtu per day. See related discussion under the caption "—The Utilities' ability to meet their customers' natural gas requirements may be impaired if contracted gas supplies, interstate pipeline and/or storage services are not available or delivered in a timely manner" under Item 1A, Risk Factors, and in Note 15, Regulatory Matters, of the Notes to Financial Statements in Item 8.

In fiscal year 2022, Spire Missouri purchased natural gas from 24 different suppliers to meet its total service area current gas sales and storage injection requirements. Spire Missouri entered into firm agreements with suppliers including major producers and marketers providing flexibility to meet the temperature-sensitive needs of its customers. Natural gas purchased by Spire Missouri for delivery to its service areas included 48.3 billion cubic feet (Bcf) through the Southern Star Central Gas Pipeline, Inc. (Southern Star) system, 26.3 Bcf through the Spire STL Pipeline, 26.3 Bcf through the Enable Mississippi River Transmission LLC (MRT) system, 6.3 Bcf through the Panhandle Eastern Pipe Line Company, LP (PEPL) system, 5.5 Bcf through the Rockies Express Pipeline, LLC (REX) system, and 4.5 Bcf through the Tallgrass Interstate Gas Transmission, LLC (TIGT) system. Spire Missouri also holds firm transportation arrangements on several other interstate pipeline systems that provide access to gas supplies upstream. Some of Spire Missouri's commercial and industrial customers purchased their own gas with Spire Missouri transporting 52.0 Bcf to them through its distribution system.

The fiscal year 2022 peak day send out of natural gas to Spire Missouri customers, including transportation customers, occurred on January 20, 2022. The average temperature was 11 degrees Fahrenheit in both St. Louis and Kansas City. On that day, Spire Missouri's customers consumed 1.58 Bcf of natural gas. For eastern Missouri, this peak day demand was met with natural gas transported to St. Louis through the MRT, Missouri Gas Pipeline LLC, Spire STL Pipeline, and Southern Star transportation systems, and from Spire Missouri's on-system storage. For western Missouri, this peak day demand was met with natural gas transported to Kansas City through the Southern Star, PEPL, TIGT, and REX transportation systems.

Spire Alabama's distribution system is connected to two major interstate natural gas pipeline systems, Southern Natural Gas Company, L.L.C. (Southern Natural Gas) and Transcontinental Gas Pipe Line Company, LLC (Transco). It is also connected to two intrastate natural gas pipeline systems.

Spire Alabama purchases natural gas from various natural gas producers and marketers. Certain volumes are purchased under firm contractual commitments with other volumes purchased on a spot market basis. The purchased volumes are delivered to Spire Alabama's system using a variety of firm transportation, interruptible transportation and storage capacity arrangements designed to meet the system's varying levels of demand.

In fiscal 2022, Spire Alabama purchased natural gas from 27 different suppliers to meet current gas sales, storage injection, and liquefied natural gas (LNG) liquefaction requirements, of which one supplier is under a long-term supply agreement. Approximately 68.2 Bcf was purchased for delivery by Southern Natural Gas, 3.7 Bcf by Transco, and 11.0 Bcf through intrastate pipelines to the Spire Alabama delivery points for its residential, commercial, and industrial customers.

The fiscal 2022 peak day send out for Spire Alabama was 0.5 Bcf on February 14, 2022, when the average temperature was 32 degrees Fahrenheit in Birmingham, of which 100% was met with supplies transported through Southern Natural Gas, Transco, and intrastate facilities.

Spire Gulf's distribution system is directly connected to interstate pipelines, natural gas processing plants and gas storage facilities. Spire Gulf buys from a variety of producers and marketers, with BP Energy Company being the primary supplier.

Natural Gas Storage

Spire Missouri believes it currently has ample storage capacity to meet the demands of its distribution system, particularly to augment its supply during peak demand periods; however, see related discussion of Spire STL Pipeline under the caption "—The Utilities' ability to meet their customers' natural gas requirements may be impaired if contracted gas supplies, interstate pipeline and/or storage services are not available or delivered in a timely manner" under Item 1A, Risk Factors, and in Note 15, Regulatory Matters, of the Notes to Financial Statements in Item 8. Spire Missouri has a contractual right to store 21.5 Bcf of gas in MRT's storage facility located in Unionville, Louisiana, 16.3 Bcf of gas storage in Southern Star's system storage facilities located in Kansas and Oklahoma, and 1.4 Bcf of firm storage on PEPL's system storage. MRT's tariffs allow injections into storage from May 1 through November 1 and require the withdrawal from storage of all but 4.3 Bcf from November 1 through May 1. Southern Star tariffs allow both injections and withdrawals into storage year-round with ratchets that restrict the associated flows dependent upon the underlying inventory level per the contracts.

In addition, Spire Missouri supplements pipeline gas with natural gas withdrawn from its own underground storage field located in St. Louis and St. Charles Counties in Missouri. The field is designed to provide approximately 0.3 Bcf of natural gas withdrawals on a peak day, and provides the ability to reinject natural gas during the heating season to replenish or increase deliverability, subject to maximum annual net withdrawals of approximately 4.0 Bcf of natural gas based on the inventory level that Spire Missouri plans to maintain.

Spire Alabama has a contractual right to store 12.7 Bcf of gas with Southern Natural Gas, 0.5 Bcf of gas with Gulf South Pipeline, 0.2 Bcf of gas with Transco and 0.2 Bcf of gas with Tennessee Gas Pipeline. In addition, Spire Alabama has 2.0 Bcf of LNG storage that can provide the system with up to an additional 0.2 Bcf of natural gas daily to meet peak day demand.

Spire Gulf obtains adequate storage capacity through Gulf South Pipeline Company, LP, and Enstor Gas, LLC's Bay Gas Storage.

Union Agreements

The Company believes labor relations with its employees are good. Should that condition change, the Company could experience labor disputes, work stoppages or other disruptions that could negatively impact the Company's system operations, customer service, results of operations and cash flows.

The following table presents the Company's various labor agreements as of September 30, 2022:

Union	Local	Employees Covered	Contract Start Date	Contract End Date
Spire Missouri				
United Steel, Paper and Forestry, Rubber Manufacturing, Allied-Industrial and Service Workers International Union (USW)	884	68	August 10, 2021	July 31, 2024
USW	11-6	843	August 1, 2021	July 31, 2024
USW	11-6-03	101	August 1, 2021	July 31, 2024
USW	12561	130	August 1, 2022	July 31, 2025
USW	14228	44	August 1, 2022	July 31, 2025
USW	11-267	28	August 1, 2022	July 31, 2025
International Brotherhood of Electrical Workers	53	2	October 1, 2022	September 30, 2025
Gas Workers Metal Trades locals of the United Association of Journeyman and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada	781-Kansas City	216	August 1, 2022	July 31, 2025
Gas Workers Metal Trades locals of the United Association of Journeyman and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada	781-Monett	52	August 1, 2022	July 31, 2025
Total Spire Missouri		1,484		
Spire Alabama				
USW	12030	235	May 1, 2020	April 30, 2023
United Association of Gas Fitters	548	221	May 1, 2022	April 30, 2025
Total Spire Alabama		456		
Spire Gulf				
USW	541	68	August 1, 2020	July 31, 2023
Total Spire		2,008		

Operating Revenues and Customer Information

The following tables present information on Spire's revenues and volume sold and transported (before intersegment eliminations), and annual average numbers of customers for the three years ended September 30, 2022, 2021 and 2020.

Gas Utility Operating Revenues

(% of Total)	2022	2021	2020
Residential	73%	58%	68%
Commercial & Industrial	17%	28%	22%
Transportation	6%	6%	6%
Other	4%	8%	4%
Total	100%	100%	100%

Gas Utility Volume Sold and Transported

(In millions of CCF)	2022	2021	2020
Residential	994.7	1,069.6	1,033.5
Commercial & Industrial	468.9	479.0	464.1
Transportation	1,617.6	1,614.7	1,637.8
Interruptible	11.8	15.0	14.5
Total System	3,093.0	3,178.3	3,149.9
Off-System	82.0	69.4	83.2
Total	3,175.0	3,247.7	3,233.1

Gas Utility Customers	2022	2021	2020
Residential	1,618,515	1,612,385	1,599,693
Commercial & Industrial	113,077	112,635	112,566
Transportation	1,023	846	847
Interruptible	50	63	67
Total	1,732,665	1,725,929	1,713,173

Total annual average number of customers for Spire Missouri and Spire Alabama for fiscal 2022 was 1,199,932 and 430,137, respectively.

Regulatory Matters

For details on regulatory matters, see Note 15, Regulatory Matters, of the Notes to Financial Statements in Item 8.

Other Pertinent Matters

Spire Missouri is the only distributor of natural gas within its franchised service areas, while Spire Alabama is the main distributor of natural gas in its service areas. Spire Missouri and Spire Alabama have franchises in nearly all the communities where they provide service with terms varying from five years to an indefinite duration. A franchise is essentially a municipal permit to install and maintain pipes and construct other facilities in the community. All of the franchises are free from unduly burdensome restrictions and are adequate for the conduct of Spire Missouri's and Spire Alabama's current public utility businesses in their respective states. In recent years, although certain franchise agreements have expired, the Utilities have continued to provide service in those communities without formal franchises.

The principal competition for the Utilities comes from the local electric companies. Other competitors in the service areas include suppliers of fuel oil, coal, and propane, as well as natural gas pipelines that can directly connect to large volume customers. Coal has been price competitive as a fuel source for very large boiler plant loads, but environmental requirements have shifted the economic advantage to natural gas. Oil and propane can be used to fuel boiler loads and certain direct-fired process applications, but these fuels require on-site storage, thus limiting their competitiveness. Competition also comes from district steam systems in the downtown areas of both St. Louis and Kansas City and from municipally or publicly owned natural gas distributors located adjacent to the Alabama service territories. Direct use of renewables will continue to grow in the future and compete against distributed generation using natural gas.

Residential, commercial, and industrial customers represent approximately 94% and 81% of fiscal 2022 operating revenues for Spire Missouri and Spire Alabama, respectively. Given the current level of natural gas supply and market conditions, the Utilities believe that the relative comparison of natural gas equipment and operating costs with those of competitive fuels will not change significantly in the foreseeable future, and that these markets will continue to be supplied by natural gas. In new multi-family and commercial rental markets, the Utilities' competitive exposures are presently limited to space and water heating applications.

Spire Missouri and Spire Alabama offer gas transportation service to its large commercial and industrial customers. Transportation customers represent approximately 3% and 15% of fiscal 2022 operating revenues for Spire Missouri and Spire Alabama, respectively. The Spire Missouri tariff approved for that type of service produces a margin similar to that which Spire Missouri would have received under their regular sales rates. Similarly, Spire Alabama's tariff is based on Spire Alabama's sales profit margin so that operating margins are unaffected.

The Utilities are subject to various environmental laws and regulations that, to date, have not materially affected the Utilities' or the Company's financial position and results of operations. For a detailed discussion of environmental matters, see Note 16, Commitment and Contingencies, of the Notes to Financial Statements in Item 8.

GAS MARKETING

Spire Marketing is engaged in the marketing of natural gas and related services throughout the United States, which includes customers within and outside of the Utilities' service areas. For fiscal 2022 and 2021, Spire Marketing volumes averaged 1.73 Bcf/day and 2.02 Bcf/day, respectively. The majority of Spire Marketing's business is derived from the procurement and physical delivery of natural gas to a diverse customer base, primarily in the central and southern U.S. Through its retail operations, Spire Marketing offers natural gas marketing services to large commercial and industrial customers, while its wholesale business consists of producers, pipelines, power generators, municipalities, storage operators, and utility companies. Wholesale activities currently represent a majority of the total Gas Marketing business. The Gas Marketing strategy is to leverage its market expertise and risk management skills to manage and optimize the value of its portfolio of commodity, transportation, park and loan, and storage contracts while controlling costs and acting on new marketplace opportunities.

In the course of its business, Spire Marketing enters into agreements to purchase natural gas at a future date in order to lock up supply to cover future sales commitments to its customers. To secure access to the markets it serves, Spire Marketing contracts for transportation capacity on various pipelines from pipeline companies directly and from other parties through the secondary capacity market. Throughout fiscal 2022, Spire Marketing held approximately 1.1 Bcf per day of firm transportation capacity. In addition, to ensure reliability of service and to provide operational flexibility, Spire Marketing enters into firm storage contracts and interruptible park and loan transactions with various companies, where it is able to buy and retain gas to be delivered at a future date, at which time it sells the natural gas to third parties. As of September 30, 2022, Spire Marketing has contracted for approximately 28.2 Bcf of such storage and park and loan capacity for the 2022-2023 winter season.

OTHER

Other components of the Company's consolidated information include:

- Spire's natural gas midstream operations consisting of Spire STL Pipeline and Spire Storage West LLC ("Spire Storage"), described below;
- Spire's subsidiaries engaged in the operation of a propane pipeline and risk management, among other activities; and
- unallocated corporate items, including certain debt and associated interest costs.

Spire STL Pipeline is a wholly owned subsidiary of Spire which owns and operates a 65-mile pipeline connecting the Rockies Express Pipeline in Scott County, Illinois, to delivery points in St. Louis County, Missouri, including Spire Missouri's storage facility. Spire STL Pipeline's operating revenue is derived primarily from Spire Missouri as its foundation shipper. The pipeline is under the jurisdiction of the Federal Energy Regulatory Commission (FERC) and is currently permitted to deliver natural gas supply into eastern Missouri under a temporary certificate authorization from FERC. See related discussion under the caption "—Failing to secure a permanent re-authorization of the Spire STL Pipeline to operate could adversely affect the Company" under "Item 1A. Risk Factors" and in Note 15, Regulatory Matters, of the Notes to Financial Statements in Item 8.

Spire Storage is engaged in the storage of natural gas in the western region of the United States. The facility consists of two storage fields operating under one FERC market-based rate tariff currently authorized to provide up to 55 Bcf of storage capacity to customers. The actual storage capacity was 23 Bcf as of September 30, 2022, and management is in the process of expanding it to 39 Bcf by 2025.

Item 1A. Risk Factors

Spire's and the Utilities' business and financial results are subject to a number of risks and uncertainties, including those set forth below. The risks described below are those the Company and the Utilities consider to be material. When considering any investment in Spire or the Utilities' securities, investors should carefully consider the following information, as well as information contained in the caption "Forward-Looking Statements," Item 7A, and other documents Spire, Spire Missouri, and Spire Alabama file with the SEC. This list is not exhaustive, and Spire's and the Utilities' respective management places no priority or likelihood based on the risk descriptions, order of presentation or grouping by subsidiary. All references to dollar amounts are in millions.

RISKS AND UNCERTAINTIES THAT RELATE TO THE BUSINESS AND FINANCIAL RESULTS OF SPIRE AND ITS SUBSIDIARIES

Climate change and regulatory and legislative developments in the energy industry related to climate change may in the future adversely affect operations and financial results.

Climate change, and regulatory, public policy, or legislative changes to address the potential for climate change, could adversely affect operations and financial results of the Company. Management believes it is likely that any such resulting impacts would occur over a long period of time and thus would be difficult to quantify with any degree of specificity. To the extent climate change results in warmer temperatures, financial results could be adversely affected through lower gas volumes and revenues and reduced marketing opportunities. Another possible impact of climate change may be more frequent and more severe weather events, such as hurricanes and tornadoes, which could increase costs to repair damaged facilities and restore service to customers or result in lost revenues if the Company were unable to deliver natural gas to customers. Such weather events could also disrupt our usual gas supplies and make it impossible or extremely costly to find replacement gas for our customers. To the extent such impacts are not covered by insurance or recovered in rates, the foregoing events could have a material adverse effect on the Company's financial condition and results of operations.

In addition, there have been a number of federal, state and local legislative and regulatory initiatives proposed in recent years in an attempt to control or limit the effects of global warming and overall climate change, including greenhouse gas emissions, such as methane and carbon dioxide. The adoption in the future of this type of legislation by Congress or similar legislation by states or localities, or the adoption of related regulations by federal, state or local governments mandating a substantial reduction in greenhouse gas emissions, restricting the use of fossil fuels, such as natural gas, or restricting the construction of infrastructure necessary to deliver natural gas to customers could have far-reaching and significant impacts on the energy industry. Such new legislation or regulations could result in increased compliance costs or additional operating restrictions, affect the demand for natural gas or impact the prices charged to customers. At this time, we cannot predict the potential impact of such laws or regulations that may be adopted on the Company's and the Utilities' future business, financial condition or financial results.

Failing to secure a permanent re-authorization of the Spire STL Pipeline to operate could adversely affect the Company.

On June 22, 2021, the U.S. Court of Appeals for the District of Columbia Circuit issued an order vacating the Spire STL Pipeline's FERC certificates to operate and remanding the proceeding back to the FERC, which took effect on October 8, 2021. On September 14, 2021, and December 3, 2021, the FERC issued temporary certificates to allow the pipeline to continue operating indefinitely while it considers approval of a new permanent certificate.

The court decision to vacate the Spire STL Pipeline's Certificate of Public Convenience and Necessity previously issued by the FERC in 2018 could, depending on the course of action the FERC takes, cause a temporary or permanent halt in the natural gas supply transported by the pipeline or result in new regulatory conditions imposed on the pipeline, any of which could adversely affect the Company (including Spire Missouri) and our customers.

Spire Missouri relies on the Spire STL Pipeline to transport natural gas into the St. Louis region. In the event the pipeline is taken out of service or even as a result of regulatory uncertainty and business constraints associated with ongoing temporary authorization of the pipeline, Spire Missouri's customers, financial condition and results of operations may be adversely impacted, which could result in a material adverse effect on the Company's financial condition and results of operations, as discussed under RISKS THAT RELATE TO THE GAS UTILITY SEGMENT below.

In addition, in the event the pipeline is taken out of service, the Company's financial condition and results of operations may be adversely impacted by impairment of Spire STL Pipeline's assets, currently carried at over $270 million, and other effects. Spire STL Pipeline will continue to pursue all legal and regulatory avenues to ensure its continued and future operation.

Reductions in capacity of interconnecting, third-party pipelines could cause a reduction in volumes transported by the Spire STL Pipeline, which could adversely affect the Company.

Spire STL Pipeline is dependent upon third-party pipelines and other facilities to provide delivery options to and from its pipeline. If any pipeline connection were to become unavailable for volumes of natural gas due to repairs, damage to the facility, lack of capacity or any other reason, Spire STL Pipeline's ability to continue shipping natural gas to end markets could be restricted, and to the extent not mitigated by contractual indemnification, insurance or tariffs, would thereby reduce its revenues. Any permanent interruption at any key pipeline interconnect that causes a material reduction in volumes transported on its pipeline could result in an impairment loss that could have a material adverse effect on the Company's financial condition and results of operations.

As a holding company, Spire depends on its operating subsidiaries to meet its financial obligations.

Spire is a holding company with no significant assets other than the stock of its operating subsidiaries and cash investments. Spire, and Spire Missouri prior to the holding company's formation in 2000, has paid common stock dividends continuously since 1946. Spire's ability to pay dividends to its shareholders is dependent on the ability of its subsidiaries to generate sufficient net income and cash flows to pay upstream dividends and make loans or loan repayments. In addition, because it is a holding company and the substantial portion of its assets are represented by its holdings in the Utilities, the risks faced by the Utilities as described below under RISKS THAT RELATE TO THE GAS UTILITY SEGMENT may also adversely affect Spire's cash flows, liquidity, financial condition and results of operations.

A downgrade in Spire's and/or its subsidiaries' credit ratings may negatively affect its ability to access capital and its cost of capital.

Currently, Spire, Spire Missouri, and Spire Alabama have investment grade credit ratings. There is no assurance that such credit ratings for any of the Spire companies will remain in effect for any given period of time or that such ratings will not be lowered, suspended or withdrawn entirely by the rating agencies, if, in each rating agency's judgment, circumstances so warrant. Spire has a working capital line of credit to meet its short-term liquidity needs. Spire's line of credit may be used to meet the liquidity needs of any of its subsidiaries, subject to sublimits. If the rating agencies lowered the credit rating at any of these entities, particularly below investment grade, it might significantly limit that entity's ability to secure new or additional credit facilities and would increase its costs of borrowing. Spire's or the Utilities' ability to borrow under current or new credit facilities and costs of that borrowing have a direct impact on their ability to execute their operating strategies.

Pipeline integrity programs and repairs may impose significant costs and liabilities on the Company.

The U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA) requires pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines and to take additional measures to protect pipeline segments located in areas where a leak or rupture could potentially do the most harm. PHMSA constantly updates its regulations to ensure the highest levels of pipeline safety. As the operator of pipelines, Spire is required to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipelines;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventative and mitigating actions.

The Company is required to maintain pipeline integrity programs that are intended to assess pipeline integrity. Any repair, remediation, preventative or mitigating actions may require significant capital and operating expenditures. Should the Company fail to comply with applicable statutes and the PHMSA Office of Pipeline Safety's rules and related regulations and orders, it could be subject to significant penalties and fines.

Transporting, distributing, and storing natural gas and propane involves numerous risks that may result in accidents and other operating risks and costs.

Natural gas transportation, distribution and storage activities inherently involve a variety of hazards and operations risks, such as leaks, accidental explosions, damage caused by third parties, and mechanical problems, which could cause substantial financial losses. In addition, these risks could result in serious injury to employees and non-employees, loss of human life, significant damage to property, environmental pollution, impairment of operations, and substantial losses to the Company and its subsidiaries. The location of pipelines and storage facilities near populated areas, including residential areas, commercial business centers, and industrial sites, could increase the level of damages resulting from these risks. Similar risks also exist for Spire Missouri's propane storage, transmission and minor distribution operations. These activities may subject the Company to litigation or administrative proceedings. Such litigation or proceedings could result in substantial monetary judgments, fines, or penalties against the Company and its subsidiaries or be resolved on unfavorable terms. The Utilities and other Spire businesses are subject to federal and state laws and regulations requiring them to maintain certain safety and system integrity measures by identifying and managing storage and pipeline risks. Compliance with these laws and regulations, or future changes in these laws and regulations, may result in increased capital, operating and other costs which may not be recoverable in a timely manner from customers in rates. In accordance with customary industry practices, the Utilities and other Spire businesses maintain insurance against a significant portion, but not all, of these risks and losses. To the extent that the occurrence of any of these events is not fully covered by insurance, it could adversely affect the financial condition and results of operations of the Company and its subsidiaries.

In connection with acquisitions, Spire and Spire Missouri recorded goodwill and long-lived assets that could become impaired and adversely affect its financial condition and results of operations.

Spire and Spire Missouri assess goodwill for impairment annually or more frequently if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value. The Company and Spire Missouri assess their long-lived assets for impairment whenever events or circumstances indicate that an asset's carrying amount may not be recoverable. To the extent the value of goodwill or long-lived assets becomes impaired, the Company and Spire Missouri may be required to incur impairment charges that could have a material impact on their results of operations.

Since interest rates are a key component, among other assumptions, in the models used to estimate the fair values of the Company's reporting units, rises in interest rates would generally decrease the calculated fair values and future impairments may occur. Due to the subjectivity of the assumptions and estimates underlying the impairment analysis, Spire and Spire Missouri cannot provide assurance that future analyses will not result in impairment. These assumptions and estimates include projected cash flows, current and future rates for contracted capacity, growth rates, weighted average cost of capital and market multiples.

Changes to income tax policy, certain tax elections, tax regulations and future taxable income could adversely impact the Company's financial condition and results of operations.

The Company has significantly reduced its current federal and state income tax obligations over the past few years through tax planning strategies including the use of bonus depreciation deductions for certain expenditures for property. As a result, the Company has generated large annual taxable losses that have resulted in significant federal and state net operating losses. The Company plans to utilize these net operating losses in the future to reduce income tax obligations. The value of these net operating losses could be reduced if the Company cannot generate enough taxable income in the future to utilize all of the net operating losses generated prior to the Tax Cuts and Jobs Act of 2017 before they expire due to lower-than-expected financial performance or regulatory actions.

Changes to income tax policy, laws and regulations, including but not limited to changes in tax rates, the deductibility of certain expenses including interest and state and local income taxes and/or changes in the deductibility of certain expenditures for property, could adversely impact the Company. Those impacts could include reducing the value of its net operating losses and could result in material charges to earnings. Further, the Company's financial condition and results of operations may be adversely impacted. Notably, the Inflation Reduction Act became effective on August 16, 2022. This new law provides various credits and incentives with respect to clean energy. The Company is evaluating the impact and applicability of these programs to its operations, but they are not expected to have a material impact on the Company.

Spire's pension and other postretirement benefit plans are subject to investment and interest rate risk that could negatively impact its financial condition.

The Company and its subsidiaries have pension and other postretirement benefit plans that provide benefits to many of their employees and retirees. Costs of providing benefits and related funding requirements of these plans are subject to changes in the market value of the assets that fund the plans. The funded status of the plans and the related costs reflected in the Company's financial statements are affected by various factors, which are subject to an inherent degree of uncertainty, including economic conditions, financial market performance, interest rates, life expectancies and demographics. Recessions and volatility in the domestic and international financial markets have negatively affected the asset values of Spire's pension plans at various times in the past. Poor investment returns or lower interest rates may necessitate accelerated funding of the plans to meet minimum federal government requirements, which could have an adverse impact on the Company's and its subsidiaries' financial condition and results of operations. For more information, including regulatory provisions affecting the Utilities' plans, see Note 13, Pension Plans and Other Postretirement Benefits, of the Notes to Financial Statements in Item 8.

The Company's natural gas storage business includes inherent geologic and operational risks, as well as risks from competition and changes in market fundamentals.

The Company plans to continue to increase capacity, improve operating performance, and improve the integrity of its storage fields and associated above-ground facilities of Spire Storage. Construction of such assets is subject to various risks and uncertainties, including supply chain and labor disruptions, weather conditions during construction, equipment failures and construction quality issues. Any such disruptions, as well as any negative effects from the risks discussed below, could result in an impairment of Spire's investment in the project, and such impairment could have a material adverse effect on the Company's financial condition and results of operations.

Any damage to the Spire Storage facilities or pipelines, or lack of integrity to its storage fields, including damages caused by a blow-out, to the extent not covered by insurance, could have a material adverse effect on the Company's financial condition and results of operations.

The Company's storage assets are connected to third-party-owned pipelines. The continuing operation of such third-party pipelines is not within its control. If any of these pipelines become unable to transport, treat or process natural gas or natural gas liquids, or if the volumes it gathers or transports do not meet the quality requirements of such pipelines, the Company's revenues and cash flows could be adversely affected.

The Company does not own all the land on which its storage facilities were constructed, and it is, therefore, subject to the possibility of more onerous terms or increased costs to retain necessary land use, if and when applicable property rights expire or are renewed. Changes in the terms of such land use could have an adverse impact on the financial condition and results of operations of the Company's storage business.

Spire Storage is subject to competition from similar services provided by pipelines and from competing independent storage providers capable of serving its customers. Natural gas storage is a competitive business, with competitors having the ability to expand storage capacity. Increased competition in the natural gas storage business could reduce the demand and drive rates down for the Company's natural gas storage services.

Storage businesses are affected by various gas market fundamentals which impact the level of demand for storage services and the rates that can be charged for these services. These market fundamentals include: seasonal price spread; monthly, daily and hourly price volatility; locational basis for pricing points on pipelines connected to a storage facility; seasonal, daily and hourly weather; and operational impacts in supply and market areas served by a storage facility and its connected pipelines. These fundamentals have varying and potentially material adverse impacts on the various services offered by storage facilities and the rates that can be charged for these services in the market. These services include long-term firm storage, short-term park and loan, wheeling, and optimization. Rates below the variable costs to operate a storage facility could result in a decision to not operate all the capacity in the facility or to operate the facility at a loss if required to fulfill firm customer contract obligations. A sustained decline in these rates or a shut-in of all or a portion of one or more facilities' capacity could have an adverse impact on the Company's financial condition and results of operations.

RISKS THAT RELATE TO THE GAS UTILITY SEGMENT

Regulation of the Utilities' businesses may impact rates they are able to charge, costs, and profitability.

The Utilities are subject to regulation by federal, state and local authorities. At the state level, the Utilities are regulated in Missouri by the Missouri Public Service Commission (MoPSC), in Alabama by the Alabama Public Service Commission (APSC), and in Mississippi by the Mississippi Public Service Commission (MSPSC). These state public service commissions regulate many aspects of the Utilities' distribution operations, including construction and maintenance of facilities, operations, safety, the rates the Utilities may charge customers, the terms of service to their customers, transactions with their affiliates, the rate of return they are allowed to realize, and the accounting treatment for certain aspects of their operations. For further discussion of these accounting matters, see Regulatory Accounting under Critical Accounting Estimates in Item 7.

Accounting for the economics of rate regulation affects multiple financial statement line items (such as property, plant, and equipment; regulatory assets and liabilities; operating revenues; and operating expenses) and affects multiple disclosures in the Company's financial statements. There is a risk that the state public service commissions will not approve full recovery of the costs of providing utility service or recovery of all amounts invested in the utility business and a reasonable return on that investment. A material disallowance of deferred costs could adversely affect the Utilities' results of operations.

The MoPSC also approves Spire Missouri's Infrastructure System Replacement Surcharge (ISRS). The ISRS allows Spire Missouri expedited recovery for its investment to upgrade its infrastructure and enhance its safety and reliability without the necessity of a formal rate case. Such investments are subject to review, and there is risk that any material disallowance of costs under ISRS could adversely affect the timing of revenues and cash flows.

The Utilities' ability to obtain and timely implement rate increases and rate supplements to maintain the current rate of return is subject to regulatory review and approval. There can be no assurance that they will be able to obtain rate increases or rate supplements or continue earning the current authorized rates of return. Spire Alabama's and Spire Gulf's rate setting process, Rate Stabilization and Equalization (RSE), is subject to regulation by the APSC and is implemented pursuant to APSC orders expiring September 30, 2025. RSE adjustments would continue after that date unless the APSC enters an order to the contrary in a manner consistent with the law. Spire Mississippi is subject to regulation by the MSPSC and utilizes the Rate Stabilization Adjustment (RSA) Rider. For further details, see Note 15, Regulatory Matters, of the Notes to Financial Statements in Item 8.

The Utilities could incur additional costs if required to adjust to new laws or regulations, revisions to existing laws or regulations or changes in interpretations of existing laws or regulations. In addition, as the regulatory environment for the natural gas industry increases in complexity, the risk of inadvertent noncompliance could also increase. If the Utilities fail to comply with applicable laws and regulations, whether existing or new, they could be subject to fines, penalties or other enforcement action by the authorities that regulate the Utilities' operations.

Significantly warmer-than-normal weather conditions, the effects of climate change, legislative and regulatory initiatives in response to climate change or in support of increased energy efficiency, and other factors that influence customer usage may affect the Utilities' sale of heating energy and adversely impact their financial position and results of operations.

The Utilities' earnings are primarily generated by the sale of heating energy. Spire Missouri and Spire Mississippi each have a Weather Normalization Adjustment rider, Spire Alabama has a Temperature Adjustment Rider, and Spire Gulf has a Weather Impact Normalization Factor. These mechanisms, approved by the respective state regulatory body, provide better assurance of the recovery of fixed costs and margins during winter months despite variations in sales volumes due to the impacts of weather, while the annual rate designs of Alabama and Mississippi help adjust for other factors that affect customer usage. However, significantly warmer-than-normal weather conditions in the Utilities' service areas and other factors, such as climate change, alternative energy sources and increased efficiency of gas furnaces and other appliances, may result in reduced profitability and decreased cash flows attributable to lower gas sales. Furthermore, continuation of these adjustment factors is subject to regulatory discretion.

In addition, legislative and regulatory initiatives by the federal, state and local governments addressing greenhouse gas emissions or restricting the use of natural gas could adversely affect customer demand. The promulgation of regulations of the emissions of greenhouse gases and efficiency for residential gas furnaces and other gas appliances or the potential enactment of congressional legislation addressing global warming and climate change may decrease customer usage, encourage fuel switching from gas to other energy forms, and may result in future additional compliance costs that could impact the Utilities' financial conditions and results of operations.

The Utilities' ability to meet their customers' natural gas requirements may be impaired if contracted gas supplies, interstate pipeline and/or storage services are not available or delivered in a timely manner.

In order to meet their customers' annual and seasonal natural gas demands, the Utilities must obtain sufficient supplies, interstate pipeline capacity, and storage capacity. If they are unable to obtain these, either from their suppliers' inability to deliver the contracted commodity or the inability to secure replacement quantities, to the extent not mitigated by tariffs, contractual indemnification or insurance, the Utilities' financial condition and results of operations may be adversely impacted. If a substantial disruption in interstate natural gas pipelines' transmission and storage capacity were to occur during periods of heavy demand, the Utilities' financial results could be adversely impacted.

In particular, the natural gas supply provided to Spire Missouri by Spire STL Pipeline is at risk due to the order issued by the U.S. Court of Appeals for the District of Columbia Circuit vacating the Spire STL Pipeline's Certificate of Public Convenience and Necessity previously issued by the FERC and remanding the matter back to the FERC for further action. The STL Pipeline is currently operating under temporary certificates. In the event this pipeline is taken out of service, either temporarily or permanently, Spire Missouri's ability to secure new pipeline contracts on other systems serving the region may be significantly constrained, and Spire Missouri would not be able to replace that supply based on similar terms or at all over the short term based on current market and operating conditions. In the event that the Spire STL Pipeline is unavailable and an extreme weather event occurs, Spire Missouri would face heightened risks, including service outages and other disruptions; the need for service restoration, creating hazards for Spire Missouri, its employees, and its customers; the potential for loss of life and property in its service territory; and associated exposure to litigation or administrative proceedings. If this pipeline is taken out of service, Spire Missouri may need to design, construct, and place in service new facilities or modify existing facilities in order to receive gas from alternate sources, giving rise to additional regulatory and business risks and hazards.

Spire Missouri will continue to pursue all legal and regulatory avenues to ensure access to reliable, affordable and safe delivery of energy for eastern Missouri. If Spire Missouri is unable to obtain sufficient pipeline capacity to meet its customers' annual and seasonal natural gas demands, Spire Missouri's financial condition and results of operations may be adversely impacted which could result in a material adverse effect on the Company's financial condition and results of operations.

The Utilities are involved in legal or administrative proceedings before various courts and governmental bodies that could adversely affect their results of operations and financial condition.

The Utilities are involved in legal or administrative proceedings before various courts and governmental bodies with respect to general claims, rates, environmental issues, gas cost prudence reviews and other matters. For further details, see Contingencies in Note 16 to the financial statements in Item 8. Adverse decisions regarding these matters, to the extent they require the Utilities to make payments in excess of amounts provided for in their financial statements, or to the extent they are not covered by insurance, could adversely affect the Utilities' results of operations and financial condition.

The Utilities' liquidity may be adversely affected by delays in recovery of their costs, due to regulation.

In the normal course of business, there is a lag between when the Utilities incur increases in certain of their costs and the time in which those costs are considered for recovery in the ratemaking process. Cash requirements for increased operating costs, increased funding levels of defined benefit pension and postretirement costs, capital expenditures, and other increases in the costs of doing business can require outlays of cash prior to the authorization of increases in rates charged to customers, as approved by the MoPSC, APSC, and MSPSC. Accordingly, the Utilities' liquidity can be adversely impacted to the extent higher costs are not timely recovered from their customers.

The Utilities' liquidity and, in certain circumstances, the Utilities' results of operations may be adversely affected by the cost of purchasing natural gas during periods in which natural gas prices are rising significantly.

The tariff rate schedules of Spire Missouri, Spire Gulf and Spire Mississippi contain Purchased Gas Adjustment (PGA) clauses and Spire Alabama's tariff rate schedule contains a Gas Supply Adjustment (GSA) rider that permit the Utilities to file for rate adjustments to recover the cost of purchased gas. Changes in the cost of purchased gas are flowed through to customers and may affect uncollectible amounts and cash flows and can therefore impact the amount of capital resources.

Currently, Spire Missouri is allowed to adjust the gas cost component of rates up to four times each year while Spire Alabama and Spire Gulf (collectively, the "Alabama Utilities") and Spire Mississippi may adjust the gas cost component of their rates on a monthly basis. Spire Missouri must make a mandatory gas cost adjustment at the beginning of the winter, in November, and during the next twelve months may make up to three additional discretionary gas cost adjustments, so long as each of these adjustments is separated by at least two months.

The MoPSC typically approves the Spire Missouri PGA changes on an interim basis, subject to refund and the outcome of a subsequent audit and prudence review. Due to such review process, there is a risk of a disallowance of full recovery of these costs. Any material disallowance of purchased gas costs would adversely affect results of operations. The Alabama Utilities' gas supply charges are submitted for APSC review on a monthly basis, regardless of whether there is a request for a change, so prudence review occurs on an ongoing basis. Spire Mississippi's PGA is adjusted on a monthly basis for the most recent charges and is filed at the MSPSC on a monthly basis.

Increases in the prices the Utilities charge for gas may also adversely affect revenues because they could lead customers to reduce usage and cause some customers to have trouble paying the resulting higher bills. These higher prices may increase bad debt expenses and ultimately reduce earnings. Rapid increases in the price of purchased gas may result in an increase in short-term debt.

To lower financial exposure to commodity price fluctuations, Spire Missouri enters into contracts to hedge the forward commodity price of its natural gas supplies. As part of this strategy, Spire Missouri may use fixed-price forward physical purchase contracts, swaps, futures, and option contracts. However, Spire Missouri does not hedge the entire exposure of energy assets or positions to market price volatility, and the coverage will vary over time. Any costs, gains, or losses experienced through hedging procedures, including carrying costs, generally flow through the PGA clause, thereby limiting Spire Missouri's exposure to earnings volatility. However, variations in the timing of collections of such gas costs under the PGA clause and the effect of cash payments for margin deposits associated with Spire Missouri's use of natural gas derivative instruments may cause short-term cash requirements to vary. These procedures remain subject to prudence review by the MoPSC.

Other than fixed-price forward physical purchase contracts, Spire Alabama, Spire Gulf, and Spire Mississippi currently do not utilize risk mitigation strategies that incorporate commodity hedge instruments, but Spire Alabama has the ability to do so through its GSA.

Environmental laws and regulations may require significant expenditures or increase operating costs.

The Utilities are subject to federal, state and local environmental laws and regulations affecting many aspects of their present and future operations. These laws and regulations require the Utilities to obtain and comply with a wide variety of environmental licenses, permits, inspections, and approvals. Failure to comply with these laws and regulations and failure to obtain any required permits and licenses may result in costs to the Utilities in the form of fines, penalties or business interruptions, which may be material. In addition, existing environmental laws and regulations could be revised or reinterpreted and/or new laws and regulations could be adopted or become applicable to the Utilities or their facilities, thereby impacting the Utilities' cost of compliance. The discovery of presently unknown environmental conditions, including former manufactured gas plant sites, and claims against the Utilities under environmental laws and regulations may result in expenditures and liabilities, which could be material. To the extent environmental compliance costs are not fully covered by insurance or recovered in rates from customers, those costs may have an adverse effect on the Utilities' financial condition and results of operations.

The Utilities' business activities are concentrated in three states.

The Utilities provide natural gas distribution services to customers in Alabama, Mississippi, and Missouri. Changes in the regional economies, politics, regulations and weather patterns of these states could negatively impact the Utilities' growth opportunities and the usage patterns and financial condition of customers and could adversely affect the Utilities' earnings, cash flows, and financial position.

The Utilities may be adversely affected by economic conditions.

Periods of slowed economic activity generally result in decreased energy consumption, particularly by industrial and large commercial companies, a loss of existing customers, and fewer new customers especially in newly constructed buildings. As a consequence, national or regional recessions or other downturns in economic activity could adversely affect the Utilities' revenues and cash flows or restrict their future growth. Economic conditions in the Utilities' service territories may also adversely impact the Utilities' ability to collect accounts receivable, resulting in an increase in bad debt expense.

Because of competition, the Utilities may not be able to retain existing customers or acquire new customers, which could have an adverse impact on their business, results of operations and financial condition.

The Utilities face the risk that larger commercial or industrial customers may bypass gas distribution services by gaining distribution directly from interstate pipelines or, in the case of Spire Alabama and Spire Gulf, also from municipally or publicly owned gas distributors located adjacent to its service territory. The Utilities cannot provide any assurance that increased competition will not have a material adverse effect on their business, financial condition or results of operations.

The Utilities compete with distributors offering a broad range of services and prices, from full-service distributors to those offering delivery only. The Utilities also compete for retail customers with suppliers of alternative energy products, principally propane and electricity, and to a growing extent, distributed sources of renewable energy. If they are unable to compete effectively, the Utilities may lose existing customers and/or fail to acquire new customers, which in the aggregate could have a material adverse effect on their business, results of operations and financial condition. Along those lines, changes in wholesale natural gas prices compared with prices for electricity, fuel oil, coal, propane, or other energy sources can significantly impact the cost of delivered natural gas, which may affect the Utilities' retention of natural gas customers and may adversely impact their financial condition and results of operations.

Regional supply/demand fluctuations and changes in national infrastructure, as well as regulatory discretion, may adversely affect the Utilities' ability to profit from off-system sales and capacity release.

Spire Missouri's and Spire Alabama's income from off-system sales and capacity release is subject to fluctuations in market conditions and changing supply and demand conditions in areas the Utilities hold pipeline capacity rights. Specific factors impacting the Utilities' income from off-system sales and capacity release include the availability of attractively priced natural gas supply, availability of pipeline capacity, and market demand. Income from off-system sales and capacity release is shared with customers. Spire Missouri and Spire Alabama are allowed to retain 25% of the net margins achieved as a result of such off-system sales and capacity release. The Utilities' ability to retain such income in the future is subject to regulatory discretion. In fact, as of April 2022, Spire Alabama can only retain the 25% of capacity release after the first $1.6 million goes entirely to customers (while sharing remains immediate for off-system sales).

RISKS THAT RELATE TO THE GAS MARKETING SEGMENT

Increased competition, fluctuations in natural gas commodity prices, expiration of supply and transportation arrangements, and infrastructure projects may adversely impact the future profitability of Gas Marketing.

Competition in the marketplace and fluctuations in natural gas commodity prices have a direct impact on the Gas Marketing business. Changing market conditions and prices, the narrowing of regional and seasonal price differentials and limited future price volatility may adversely impact its sales margins or affect its ability to procure gas supplies and/or to serve certain customers, which may reduce sales profitability and/or increase certain credit requirements caused by reductions in netting capability. Also, Gas Marketing profitability may be impacted by the effects of the expiration, in the normal course of business, of certain of its natural gas supply contracts if those contracts cannot be replaced and/or renewed with arrangements with similar terms and pricing. Although the FERC regulates the interstate transportation of natural gas and establishes the general terms and conditions under which Spire Marketing may use interstate gas pipeline capacity to purchase and transport natural gas, Spire Marketing must occasionally renegotiate its transportation agreements with a concentrated group of pipeline companies. Renegotiated terms of new agreements, or increases in FERC-authorized rates of existing agreements, may impact Gas Marketing's future profitability. Profitability may also be adversely impacted if pipeline capacity or future storage capacity secured is not fully utilized.

Reduced access to credit and/or capital markets may prevent the Gas Marketing business from executing operating strategies.

The Gas Marketing segment relies on its cash flows, ability to effect net settlements with counterparties, parental guaranties, and access to Spire's liquidity resources to satisfy its credit and working capital requirements. Spire Marketing's ability to rely on parental guaranties is dependent upon Spire's financial condition and credit ratings. If Spire's credit ratings were lowered, particularly below investment grade, counterparty acceptance of parental guaranties may diminish, resulting in decreased availability of credit. Additionally, under such circumstances, certain counterparties may require Spire Marketing to provide prepayments or cash deposits, amounts of which would be dependent upon natural gas market conditions. Reduced access to credit or increased credit requirements, which may also be caused by factors such as higher overall natural gas prices, may limit Spire Marketing's ability to enter into certain transactions. In addition, Spire Marketing has concentrations of counterparty credit risk in that a significant portion of its transactions are with (or are associated with) energy producers, utility companies, and pipelines. These concentrations of counterparties have the potential to affect the Company's overall exposure to credit risk, either positively or negatively, in that each of these three groups may be affected similarly by changes in economic, industry, or other conditions. Spire Marketing also has concentrations of credit risk in certain individually significant counterparties. Spire Marketing closely monitors its credit exposure and, although uncollectible amounts have not been significant, increased counterparty defaults are possible and may result in financial losses and/or capital limitations.

Risk management policies, including the use of derivative instruments, may not fully protect Spire Marketing's sales and results of operations from volatility and may result in financial losses.

In the course of its business, Spire Marketing enters into contracts to purchase and sell natural gas at fixed prices and index-based prices. Commodity price risk associated with these contracts has the potential to impact earnings and cash flows. To minimize this risk, Spire Marketing has a risk management policy that provides for daily monitoring of a number of business measures, including fixed price commitments.

Spire Marketing currently manages the commodity price risk associated with fixed-price commitments for the purchase or sale of natural gas by either closely matching the offsetting physical purchase or sale of natural gas at fixed prices or through the use of natural gas futures, options, and swap contracts traded on or cleared through the New York Mercantile Exchange, Inc. and/or the Intercontinental Exchange to lock in margins. These exchange-traded/cleared contracts may be designated as cash flow hedges of forecasted transactions. However, market conditions and regional price changes may cause ineffective portions of matched positions to result in financial losses. Additionally, to the extent that Spire Marketing's natural gas contracts are classified as trading activities or do not otherwise qualify for the normal purchases or normal sales designation (or the designation is not elected), the contracts are recorded as derivatives at fair value each period. Accordingly, the associated gains and losses are reported directly in earnings and may cause volatility in results of operations. Gains or losses (realized and unrealized) on certain wholesale purchase and sale contracts, consisting of those classified as trading activities, are required to be presented on a net basis (instead of a gross basis) in the statements of consolidated income. Such presentation could result in volatility in the Company's operating revenues.

As a natural gas market participant, Spire Marketing is subject to applicable FERC- and Commodity Futures Trading Commission (CFTC)-administered statutes, rules, regulations and orders, including those directed generally to prevent manipulation of or fraud involving natural gas physical transactions and financial instruments, such as futures, options and swaps. Spire Marketing could be subject to substantial penalties and fines by the FERC or CFTC, or both, for failure to comply with such rules.

Spire Marketing's ability to meet its customers' natural gas requirements may be impaired if contracted gas supplies and interstate pipeline services are not available or delivered in a timely manner.

Spire Marketing's ability to deliver natural gas to its customers is contingent upon the ability of natural gas producers, other gas marketers, and interstate pipelines to fulfill delivery obligations to Spire Marketing under firm contracts. To the extent that it is unable to obtain the necessary supplies, Spire Marketing's financial position and results of operations may be adversely impacted.

Regulatory and legislative developments pertaining to the energy industry may adversely impact Gas Marketing's results of operations and financial condition.

The Gas Marketing business is non-regulated, in that the rates it charges its customers are not currently established by or subject to approval by any regulatory body with jurisdiction over its business. However, it is subject to various laws and regulations affecting the energy industry. New regulatory and legislative actions may adversely impact Gas Marketing's results of operations and financial condition by potentially reducing customer growth opportunities and/or increasing the costs of doing business.

Gas Marketing uses bilateral contracts and derivative instruments such as futures contracts, options and swaps to hedge or mitigate ongoing commercial risks. Most standardized swaps, under the Dodd-Frank Act, are required to be cleared through a registered clearing facility and traded on a designated exchange or swap execution facility, subject to certain exceptions. In addition, the CFTC's rules require companies, including Spire Marketing, to maintain regulatory records of swap transactions, and to report swaps to centralized swap data repositories, among other compliance obligations. Although Spire Marketing may qualify for exceptions to certain of these CFTC rules, its derivatives counterparties are subject to capital, margin, documentation and business conduct requirements imposed as a result of the Dodd-Frank Act. These obligations may increase transaction costs and may make it more difficult for Spire Marketing to enter into hedging transactions on favorable terms or affect the number and/or creditworthiness of available swap counterparties. Spire Marketing's inability to enter into derivatives instruments or other commercial risk hedging transactions on favorable terms, or at all, could increase operating expenses and expose it to unhedged commercial risks, including potential adverse changes in commodity prices.

In October 2020, the CFTC finalized its rules that modify and expand the applicability of speculative position limits on the amounts of certain futures contracts (including options thereon), cash-settled "lookalike" contracts for or linked to the commodities underlying the foregoing futures contracts, as well as economically equivalent swaps containing "identical material" contractual specifications, terms and conditions as the foregoing contracts. While Spire Marketing anticipates qualifying for a bona fide hedging exemption from such limits, the CFTC's final rules and earlier adopted aggregation rules may cause Spire Marketing's hedging strategies described above to be limited if Spire Marketing is unable to qualify for an exemption.

GENERAL RISK FACTORS

Unexpected losses may adversely affect Spire's or its subsidiaries' financial condition and results of operations.

As with most businesses, there are operations and business risks inherent in the activities of Spire's subsidiaries. If, in the normal course of business, Spire or any of its subsidiaries becomes a party to litigation, such litigation could result in substantial monetary judgments, fines, or penalties or be resolved on unfavorable terms. In accordance with customary practice, Spire and its subsidiaries maintain insurance against a significant portion of, but not all, risks and losses. In addition, in the normal course of its operations, Spire and its subsidiaries may be exposed to loss from other sources, such as bad debt expense or the failure of a counterparty to meet its financial obligations. Spire and its operating companies employ many strategies to gain assurance that such risks are appropriately managed, mitigated, or insured, as appropriate. To the extent a loss is not fully covered by insurance or other risk mitigation strategies, that loss could adversely affect the Company's and/or its subsidiaries' financial condition and results of operations.

Catastrophic events may adversely affect the Company's facilities and operations.

Catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes, tropical storms, winter storms, terrorist acts, acts of civil unrest, pandemic illnesses or other similar occurrences could adversely affect the Utilities' facilities and operations, as well as those of Spire STL Pipeline and Spire Storage. The Utilities have emergency planning and training programs in place to respond to events that could cause business interruptions. However, unanticipated events or a combination of events, failure in resources needed to respond to events, or slow or inadequate response to events may have an adverse impact on the operations, financial condition, and results of operations of the Company and its subsidiaries. To the extent the impacts of such catastrophic events are not covered by insurance or recovered in rates, this could have a material adverse effect on the Company's financial condition and results of operations.

Increased dependence on technology may hinder Spire's and its subsidiaries' business operations and adversely affect their financial condition and results of operations if such technologies fail.

Spire and its subsidiaries have implemented or acquired a variety of technological tools including both Company-owned information technology and technological services provided by outside parties. These tools and systems support critical functions including Spire and its subsidiaries' integrated planning, scheduling and dispatching of field resources, its automated meter reading system, customer care and billing, procurement and accounts payable, operational plant logistics, management reporting, and external financial reporting. The failure of these or other similarly important technologies, or the Company's or its subsidiaries' inability to have these technologies supported, updated, expanded, or integrated into other technologies, could hinder their business operations and, to the extent not covered by insurance, could adversely impact their financial condition and results of operations.

Although the Company and its subsidiaries have, when possible, developed alternative sources of technology and built redundancy into their computer networks and tools, there can be no assurance that these efforts to date would protect against all potential issues related to the loss of any such technologies or the Utilities' use of such technologies.

A cyberattack may disrupt Spire's operations or lead to a loss or misuse of confidential and proprietary information or potential liability.

The Company and its subsidiaries are subject to cybersecurity risks primarily related to breaches of security pertaining to sensitive customer, employee, and vendor information maintained by the Company, its subsidiaries, or its third-party vendors in the normal course of business, as well as breaches in the technology that manages natural gas distribution operations and other business processes. A loss of confidential or proprietary data or security breaches of technology for operations or business processes could adversely affect the Company's and its subsidiaries' reputation, diminish customer confidence, disrupt operations, and subject the Company and its subsidiaries to possible financial liability, any of which could have a material effect on the Company's and its subsidiaries' financial condition and results of operations.

The Company acknowledges that increased dependence on technology increases the Company's exposure to cyberattack. The Company and its subsidiaries closely monitor both preventive and detective measures to manage these risks and maintain cyber risk insurance to mitigate a significant portion, but not all, of these risks and losses. To the extent that the occurrence of any of these cyber events is not covered by insurance, it could adversely affect the Company's and its subsidiaries' financial condition and results of operations.

Workforce risks may affect the Company's financial results.

The Company and its subsidiaries are subject to various workforce risks, including, but not limited to, the risk that it will be unable to attract and retain qualified personnel; that it will be unable to effectively transfer to new personnel the knowledge and expertise of an aging workforce as those workers retire; and that it will be unable to reach collective bargaining arrangements with the unions that represent certain of its workers, which could result in work stoppages.

Resources expended to pursue or integrate business acquisitions, investments or other business arrangements may adversely affect Spire's financial position and results of operations and return on investments made may not meet the Company's expectations.

From time to time, Spire may seek to grow through strategic acquisitions, investments or other business arrangements. Attractive acquisition and investment opportunities may be difficult to complete on economically acceptable terms. It is possible for Spire to expend considerable resources pursuing acquisitions and investments but, for a variety of reasons, decide not to move forward. Similarly, investment opportunities may be hindered or halted by regulatory or legal actions. To the extent that acquisitions or investments are made, such transactions involve a number of risks, including but not limited to, the assumption of material liabilities, the diversion of management's attention from daily operations, difficulties in assimilation and retention of employees, securing adequate capital to support the transaction, and regulatory approval. Uncertainties exist in assessing the value, risks, profitability, and liabilities associated with certain businesses or assets and there is a possibility that anticipated operating and financial efficiencies expected to result from an acquisition or investment do not develop. Additionally, there are no assurances that resources expended will achieve their intended result.

The failure to complete an acquisition successfully or to integrate acquisitions or investments it may undertake could have an adverse effect on the Spire's financial condition and results of operations and the market's perception of the Company's execution of its strategy. To the extent Spire engages in any of the above activities together with or through one or more of its subsidiaries, including the Utilities, such subsidiaries may face the same risks.

Changes in accounting standards may adversely impact the Company's financial condition and results of operations.

Spire and its subsidiaries are subject to changes in U.S. generally accepted accounting principles (GAAP), SEC regulations and other interpretations of financial reporting requirements for public utilities. Neither the Company nor any of its subsidiaries have any control over the impact these changes may have on their financial condition or results of operations nor the timing of such changes. The potential issues associated with rate-regulated accounting, along with other potential changes to GAAP that the U.S. Financial Accounting Standards Board (FASB) continues to consider may be significant.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

<u>*Spire*</u>

Refer to the information below about the principal properties of Spire Missouri and Spire Alabama. The Spire EnergySouth utilities own more than 5,000 miles of pipelines. Other properties of Spire and its subsidiaries do not constitute a significant portion of its properties. The current leases for office space in downtown St. Louis commenced in early 2015, with terms ranging from 10 to 20 years, with multiple renewal options. For further information on leases see Note 17, Leases, of the Notes to Financial Statements in Item 8.

Spire Missouri

The principal properties of Spire Missouri consist of its gas distribution system, which includes more than 31,000 miles of main and related service lines, odorization and regulation facilities, and customer meters. The mains and service lines are located in municipal streets or alleys, public streets or highways, or on lands of others for which Spire Missouri has obtained the necessary legal rights to place and operate its facilities on such property. Spire Missouri has an underground natural gas storage facility, several operating centers, and other related properties. Substantially all of Spire Missouri's utility plant is subject to the liens of its mortgage. All the properties of Spire Missouri are held in fee, by easement, or under lease agreements.

Spire Alabama

The properties of Spire Alabama consist primarily of its gas distribution system, which includes more than 24,000 miles of main and related service lines, odorization and regulation facilities, and customer meters. The mains and service lines are located in municipal streets or alleys, public streets or highways, or on lands of others for which Spire Alabama has obtained the necessary legal rights to place and operate its facilities on such property. Spire Alabama also has four LNG facilities, several operating centers, and other related properties. All of the properties of Spire Alabama are held in fee, by easement, or under lease agreements.

Item 3. Legal Proceedings

For a description of pending regulatory matters of Spire, see Note 15, Regulatory Matters, of the Notes to Financial Statements in Item 8. For a description of environmental and other legal matters, see Contingencies in Note 16 of the Notes to Financial Statements in Item 8.

Item 4. Mine Safety Disclosures

Not applicable.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS – Listed below are executive officers as defined by the SEC for Spire. Their ages, at September 30, 2022, and positions are listed below along with their business experience during the past five years.

Name	Age	Position with Company (1)	Appointed (2)
S. Sitherwood	62	President and Chief Executive Officer	February 2012
		Chairman of the Board, Spire Missouri	January 2015
		Chairman of the Board, Spire Alabama	September 2014
S. L. Lindsey	56	Executive Vice President, Chief Operating Officer	January 2020
		Executive Vice President, Chief Executive Officer of Gas Utilities and Distribution Operations (until December 2019)	October 2012
		Chief Executive Officer, Spire Missouri	December 2018
		Chief Executive Officer, Spire Alabama	September 2014
S. P. Rasche	62	Executive Vice President and Chief Financial Officer	November 2013
		Chief Financial Officer, Spire Missouri (until January 2020)	May 2012
		Chief Financial Officer, Spire Alabama (until January 2020)	September 2014
M. C. Darrell	64	Senior Vice President, Chief Legal and Compliance Officer	May 2012
M. C. Geiselhart	63	Senior Vice President, Chief Strategy and Corporate Development Officer	January 2015
S. B. Carter	50	Senior Vice President, Chief Operating Officer of Distribution Operations	January 2019
		Senior Vice President, Commercial Operations (until December 2018)	January 2017
		President, Spire Missouri	December 2018

(1) The information provided relates to the Company and its principal subsidiaries. Many of the executive officers have served or currently serve as officers or directors for other subsidiaries of the Company.

(2) Officers of Spire are normally reappointed by its Board of Directors in November of each year. Officers of Spire Missouri and Spire Alabama are normally reappointed by their boards of directors in January of each year.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters, and Issuer Purchases of Equity Securities

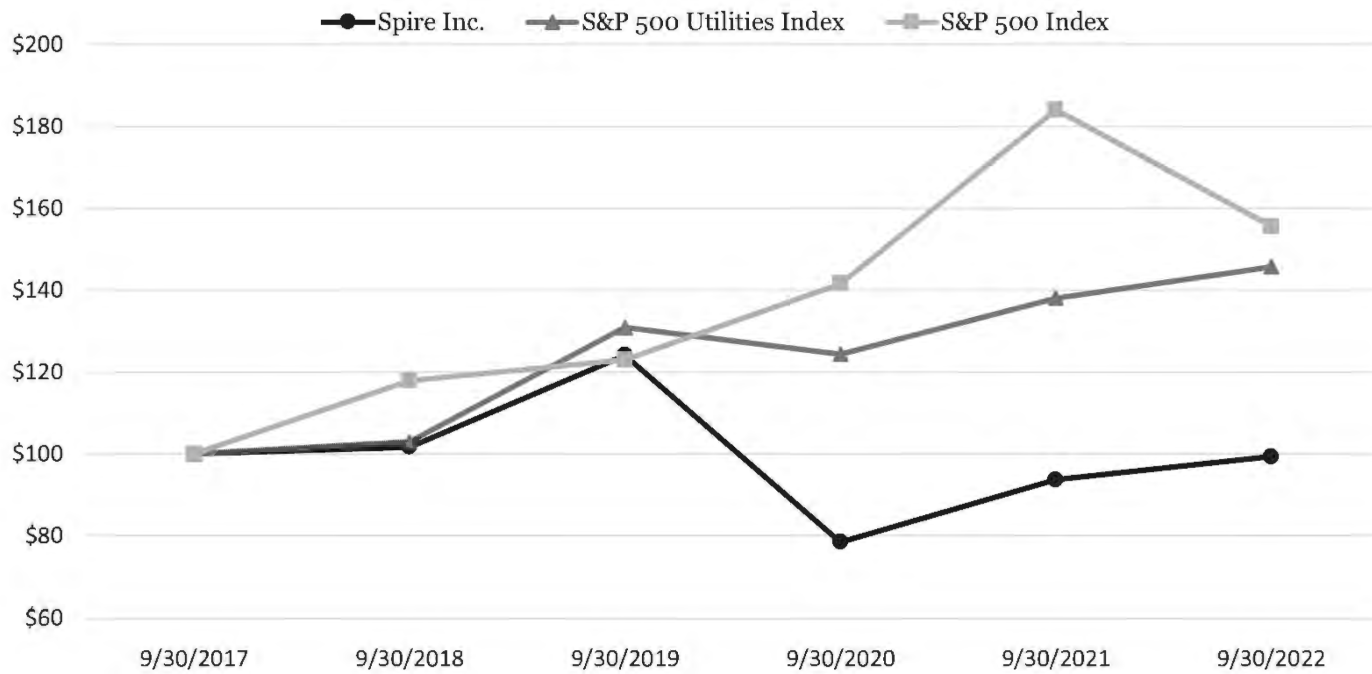
Spire

Spire's common stock trades on The New York Stock Exchange (NYSE) under the symbol "SR". The number of holders of record as of November 11, 2022 was 2,636.

Dividends are payable on the Company's common stock at the discretion of its Board of Directors (the "Board"). Spire, and Spire Missouri prior to the holding company's formation in 2000, has paid common stock dividends continuously since 1946, with 2022 marking the 19th consecutive year of increasing dividends on an annualized basis. Although the Board expects to continue paying dividends on the common stock for the foreseeable future, the declaration of dividends is not guaranteed. The amount of dividends on the common stock, if any, will depend upon the Company's financial condition, results of operations, capital requirements, and other factors.

Performance Graph

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN*



September 30	2017	2018	2019	2020	2021	2022
Spire Inc.	$ 100.00	$ 101.64	$ 124.10	$ 78.42	$ 93.66	$ 99.28
S&P 500 Utilities Index	100.00	102.93	130.82	124.32	138.01	145.71
S&P 500 Index	100.00	117.91	122.93	141.55	184.02	155.55

* Cumulative total return is based on a $100 investment on September 30, 2017, assuming reinvestment of dividends.

The S&P 500 Utilities Index is comprised of 29 utilities heavily weighted to large capitalization (median market cap of $21.9 billion) electric utilities. In 2020, stocks of small and mid cap electric utilities and gas utility companies (like Spire) in general traded lower relative to the large cap electric sector. Since then, Spire has outperformed both the S&P 500 Utilities and the S&P 500 Indices.

For disclosures related to securities authorized for issuance under equity compensation plans, see Note 3, Stock-Based Compensation, of the Notes to Financial Statements in Item 8.

During the three months ended September 30, 2022, the only repurchases of the Company's common stock were pursuant to elections by employees to have shares of stock withheld to cover employee tax withholding obligations upon the vesting of performance-based and time-vested restricted stock and stock units. The following table provides information on those repurchases:

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid Per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares that May Yet be Purchased Under the Plans or Programs
July 1, 2022 - July 31, 2022	182	$76.32	—	—
August 1, 2022 - August 31, 2022	—	—	—	—
September 1, 2022 - September 30, 2022	340	$68.87	—	—
Total	522	$71.47	—	—

Spire Missouri

Spire Missouri common stock is owned by its parent, Spire Inc., and is not traded on any stock exchange.

Spire Missouri's mortgage contains restrictions on its ability to pay cash dividends on its common stock, as described in further detail in Note 5, Shareholders' Equity, of the Notes to Financial Statements in Item 8. As of September 30, 2022 and 2021, the amount under the mortgage's formula that was available to pay dividends was $1,579.4 million and $1,413.4 million, respectively.

Spire Alabama

Spire Alabama common stock is owned by its parent, Spire Inc., and is not traded on any stock exchange.

Item 6. (Reserved)

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations
(Dollars in millions, except per share and per unit amounts)

INTRODUCTION

This section analyzes the financial condition and results of operations of Spire Inc. (the "Company"), Spire Missouri Inc., and Spire Alabama Inc. Spire Missouri, Spire Alabama and Spire EnergySouth are wholly owned subsidiaries of the Company. Spire Missouri, Spire Alabama and the subsidiaries of Spire EnergySouth are collectively referred to as the "Utilities." The subsidiaries of Spire EnergySouth are Spire Gulf and Spire Mississippi. This section includes management's view of factors that affect the respective businesses of the Company, Spire Missouri and Spire Alabama, explanations of financial results including changes in earnings and costs from the prior periods, and the effects of such factors on the Company's, Spire Missouri's and Spire Alabama's overall financial condition and liquidity. Unless otherwise indicated, references to years herein are references to the fiscal years ending September 30 for the Company and its subsidiaries.

Reference is made to "Item 1A. Risk Factors" and "Forward-Looking Statements," which describe important factors that could cause actual results to differ from expectations and non-historical information contained herein. In addition, the following discussion should be read in conjunction with the audited financial statements and accompanying notes thereto of Spire, Spire Missouri and Spire Alabama included in "Item 8. Financial Statements and Supplementary Data."

OVERVIEW

The Company has two reportable segments: Gas Utility and Gas Marketing. Nearly all of Spire's earnings are derived from its Gas Utility segment, which reflects the regulated activities of the Utilities. Due to the seasonal nature of the Utilities' business and the volumetric Spire Missouri rate design, earnings of Spire and each of the Utilities are typically concentrated during the heating season of November through April each fiscal year.

Gas Utility - Spire Missouri

Spire Missouri is Missouri's largest natural gas distribution utility and is regulated by the MoPSC. Spire Missouri serves St. Louis, Kansas City, and other areas throughout the state. Spire Missouri purchases natural gas in the wholesale market from producers and marketers and ships the gas through interstate pipelines into its own distribution facilities for sale to residential, commercial and industrial customers. Spire Missouri also transports gas through its distribution system for certain larger customers who buy their own gas on the wholesale market. Spire Missouri delivers natural gas to customers at rates and in accordance with tariffs authorized by the MoPSC. The earnings of Spire Missouri are primarily generated by the sale of heating energy.

Gas Utility - Spire Alabama

Spire Alabama is the largest natural gas distribution utility in the state of Alabama and is regulated by the APSC. Spire Alabama's service territory is located in central and northern Alabama. Among the cities served by Spire Alabama are Birmingham, the center of the largest metropolitan area in the state, and Montgomery, the state capital. Spire Alabama purchases natural gas through interstate and intrastate suppliers and distributes the purchased gas through its distribution facilities for sale to residential, commercial, and industrial customers and other end-users of natural gas. Spire Alabama also transports gas through its distribution system for certain large commercial and industrial customers for a transportation fee. Effective December 1, 2020, for most of these transportation service customers, Spire Alabama also purchases gas on the wholesale market for sale to the customer upon delivery to the Spire Alabama distribution system. All Spire Alabama services are provided to customers at rates and in accordance with tariffs authorized by the APSC.

Gas Utility - Spire EnergySouth

Spire Gulf and Spire Mississippi are utilities engaged in the purchase, retail distribution and sale of natural gas to approximately 100,000 customers in southern Alabama and south-central Mississippi. Spire Gulf is regulated by the APSC, and Spire Mississippi is regulated by the MSPSC.

Gas Marketing

Spire Marketing is engaged in the marketing of natural gas and related activities on a non-regulated basis and is reported in the Gas Marketing segment. Spire Marketing markets natural gas to customers across the U.S. (and into Canada), including customers inside and outside of the Utilities' service areas. It holds firm transportation and storage contracts in order to effectively manage its transactions with counterparties, which primarily include producers, municipalities, electric and gas utility companies, and large commercial and industrial customers.

Other

Other components of the Company's consolidated information include:
- Spire STL Pipeline, a subsidiary of Spire providing interstate natural gas pipeline transportation services;
- Spire Storage, a subsidiary of Spire providing interstate natural gas storage services;
- Spire's subsidiaries engaged in the operation of a propane pipeline and risk management, among other activities; and
- unallocated corporate items, including certain debt and associated interest costs.

Business Evaluation Factors

Based on the nature of the business of the Company and its subsidiaries, as well as current economic conditions, management focuses on several key variables in evaluating the financial condition and results of operations and managing the business.

For the Gas Utility segment, these include:
- the Utilities' ability to recover from their customers the costs of purchasing and distributing natural gas;
- the impact of weather and other factors, such as customer conservation, on revenues and expenses;
- changes in the regulatory environment at the federal, state, and local levels, as well as decisions by regulators, that impact the Utilities' ability to earn the authorized rate of return and recover prudent costs in each of the service territories they serve;
- the Utilities' ability to access credit markets and maintain working capital sufficient to meet operating requirements;
- the effect of natural gas price volatility on the business; and
- the ability to manage costs, integrate and standardize operations, and upgrade infrastructure.

In the Gas Marketing segment, these include:
- the risks of competition;
- fluctuations and volatility in natural gas prices;
- the changing flow and availability of natural gas;
- new national infrastructure projects;
- the ability to procure firm transportation and storage services at reasonable rates;
- credit and/or capital market access; and
- counterparty risks.

Further information regarding how management seeks to manage these key variables is discussed below.

Gas Utility

The Utilities seek to provide reliable natural gas services at a reasonable cost, while maintaining and building secure and dependable infrastructures. The Utilities' strategies focus on improving both performance and the ability to recover their authorized distribution costs and rates of return. The Utilities' distribution costs are the essential, primarily fixed, expenditures they must incur to operate and maintain more than 60,000 miles of mains and services comprising their natural gas distribution systems and related storage facilities.

The Utilities' distribution costs include wages and employee benefit costs, depreciation and maintenance expenses, and other regulated utility operating expenses, excluding natural and propane gas expense. Distribution costs are considered in the rate-making process, and recovery of these types of costs is included in revenues generated through the Utilities' tariff rates. Spire Missouri's tariff rates are approved by the MoPSC, whereas Spire Alabama's tariff rates are approved by the APSC. Spire Gulf and Spire Mississippi have tariff rates that are approved by the APSC and MSPSC, respectively.

Spire Missouri and Spire Alabama also have off-system sales and capacity release income streams that are regulated by tariff but remain subject to fluctuations in market conditions. Some of the factors impacting the level of off-system sales include the availability and cost of Spire's natural gas supply, the weather in its service areas and the weather in other markets. When Spire's service areas experience warmer-than-normal weather while other markets experience colder weather or supply constraints, some of Spire's natural gas supply is available for sale to third parties not on Spire's system.

The Utilities work actively to reduce the impact of wholesale natural gas price volatility on their costs by strategically structuring their natural gas supply portfolios to increase their gas supply availability and pricing alternatives. They may also use derivative instruments to hedge against significant changes in the commodity price of natural gas. Nevertheless, the overall cost of purchased gas remains subject to fluctuations in market conditions. The Purchased Gas Adjustment (PGA) clause of Spire Missouri, Spire Gulf and Spire Mississippi and the Gas Supply Adjustment (GSA) rider of Spire Alabama allow the Utilities to flow through to customers, subject to prudence review by the public service commissions, the cost of purchased gas supplies, including costs, cost reductions and related carrying costs associated with the use of derivative instruments to mitigate volatility in the cost of natural gas. As of September 30, 2022, Spire Missouri had active derivative positions, but Spire Alabama has had no gas supply derivative instrument activity since 2010. Except in certain situations discussed under the caption "—The Utilities' ability to meet their customers' natural gas requirements may be impaired if contracted gas supplies, interstate pipeline and/or storage services are not available or delivered in a timely manner" under Item 1A, Risk Factors, and in Note 15, Regulatory Matters, of the Notes to Financial Statements in Item 8, the Utilities believe they will continue to be able to obtain sufficient gas supply. The price of natural gas supplies and other economic conditions may affect sales volumes, due to the conservation efforts of customers, and cash flows associated with the timing of collection of gas costs and related accounts receivable from customers.

The Utilities rely on short-term credit and long-term capital markets, as well as cash flows from operations, to satisfy their seasonal cash requirements and fund their capital expenditures. The Utilities access the commercial paper market through a program administered by the holding company, which then loans borrowed funds to the Utilities. The Utilities directly access the long-term bond market. Access to debt markets is dependent on current conditions in the credit and capital markets. Management focuses on maintaining a strong balance sheet and believes the Utilities currently have adequate access to credit and capital markets and will have sufficient capital resources to meet their foreseeable obligations. See the "Capital Resources" section for additional information.

Gas Marketing

Spire Marketing utilizes its natural gas supply agreements, transportation agreements, park and loan agreements, storage agreements and other executory contracts to support a variety of services to its customers at competitive prices. It closely monitors and manages the natural gas commodity price and volatility risks associated with providing such services to its customers through the use of a variety of risk management activities, including the use of exchange-traded/cleared derivative instruments and other contractual arrangements. Spire Marketing is committed to managing commodity price risk while it seeks to expand the services that it now provides. Nevertheless, income from the Gas Marketing operations is subject to more fluctuations in market conditions than the Utilities' operations.

The Gas Marketing business is directly impacted by the effects of competition in the marketplace, the impacts of new infrastructure, surplus natural gas supplies, and the addition of new demand from exports, power generation and industrial load. Spire Marketing's management expects a growing need for marketing services across the country as customers manage seasonal variability and marketplace volatility.

In addition to its own operating cash flows, Spire Marketing relies on Spire's parental guaranties to secure its purchase and sales obligations of natural gas, and it also has access to Spire's liquidity resources. A large portion of Spire Marketing's receivables are from customers in the energy industry. It also enters into netting arrangements with many of its energy counterparties to reduce overall credit and collateral exposure. On a net dollar exposure basis, the majority of Spire Marketing's customers are utilities or utility affiliates. Although Spire Marketing's uncollectible amounts are closely monitored and have not been significant, increases in uncollectible amounts from customers are possible and could adversely affect Spire Marketing's liquidity and results of operations.

Spire Marketing carefully monitors the creditworthiness of counterparties to its transactions. It performs in-house credit reviews of potential customers and may require credit assurances such as prepayments, letters of credit or parental guaranties when appropriate. Credit limits for customers are established and monitored.

Spire Marketing cannot be certain that all of its wholesale purchase and sale transactions will settle physically. As such, these transactions are designated as trading activities for financial reporting purposes, due to their settlement characteristics. Results of operations from trading activities are reported on a net basis in natural gas expenses.

In the course of its business, Spire Marketing enters into commitments associated with the purchase or sale of natural gas. In accordance with U.S. GAAP, some of its purchase and sale transactions are not recognized in earnings until the natural gas is physically delivered, while other energy-related transactions, including those designated as trading activities, are required to be accounted for as derivatives with the changes in their fair value (representing unrealized gains or losses) recorded in earnings in periods prior to settlement. Because related transactions of a purchase and sale strategy may be accounted for differently, there may be timing differences in the recognition of earnings under GAAP and economic earnings realized upon settlement. The Company reports both GAAP and net economic earnings (non-GAAP), as discussed in the section “Non-GAAP Measures”.

NON-GAAP MEASURES

Net income, earnings per share and operating income reported by Spire, Spire Missouri and Spire Alabama are determined in accordance with GAAP. Spire, Spire Missouri and Spire Alabama also provide the non-GAAP financial measures of net economic earnings, net economic earnings per share and contribution margin. Management and the Board of Directors use non-GAAP financial measures, in addition to GAAP financial measures, to understand and compare operating results across accounting periods, for financial and operational decision making, for planning and forecasting, to determine incentive compensation and to evaluate financial performance. These non-GAAP operating metrics should not be considered as alternatives to, or more meaningful than, the related GAAP measures. Reconciliations of non-GAAP financial measures to the most directly comparable GAAP measures are provided on the following pages.

Net Economic Earnings and Net Economic Earnings Per Share

Net economic earnings and net economic earnings per share are non-GAAP measures that exclude from net income the impacts of fair value accounting and timing adjustments associated with energy-related transactions, the impacts of acquisition, divestiture and restructuring activities, and the largely non-cash impacts of impairments and other non-recurring or unusual items such as certain regulatory, legislative or GAAP standard-setting actions. In addition, net economic earnings per share would exclude the impact, in the fiscal year of issuance, of any shares issued to finance acquisitions that have yet to be included in net economic earnings.

The fair value and timing adjustments are made in instances where the accounting treatment differs from what management considers the economic substance of the underlying transaction, including the following:

- Net unrealized gains and losses on energy-related derivatives that are required by GAAP fair value accounting associated with current changes in the fair value of financial and physical transactions prior to their completion and settlement. These unrealized gains and losses result primarily from two sources:
  1) changes in the fair values of physical and/or financial derivatives prior to the period of settlement; and
  2) ineffective portions of accounting hedges, required to be recorded in earnings prior to settlement, due to differences in commodity price changes between the locations of the forecasted physical purchase or sale transactions and the locations of the underlying hedge instruments;

- Lower of cost or market adjustments to the carrying value of commodity inventories resulting when the net realizable value of the commodity falls below its original cost, to the extent that those commodities are economically hedged; and

- Realized gains and losses resulting from the settlement of economic hedges prior to the sale of the physical commodity.

These adjustments eliminate the impact of timing differences and the impact of current changes in the fair value of financial and physical transactions prior to their completion and settlement. Unrealized gains or losses are recorded in each period until being replaced with the actual gains or losses realized when the associated physical transactions occur. Management believes that excluding the earnings volatility caused by recognizing changes in fair value prior to settlement and other timing differences associated with related purchase and sale transactions provides a useful representation of the economic effects of only the actual settled transactions and their effects on results of operations. While management uses these non-GAAP measures to evaluate all of its businesses, the net effect of these fair value and timing adjustments on the Utilities' earnings is minimal because gains or losses on their natural gas derivative instruments are deferred pursuant to state regulation.

Contribution Margin

In addition to operating revenues and operating expenses, management also uses the non-GAAP measure of contribution margin when evaluating results of operations. Contribution margin is defined as operating revenues less natural gas costs and gross receipts tax expense. The Utilities pass to their customers (subject to prudence review by, as applicable, the MoPSC, APSC or MSPSC) increases and decreases in the wholesale cost of natural gas in accordance with their PGA clauses or GSA riders. The volatility of the wholesale natural gas market results in fluctuations from period to period in the recorded levels of, among other items, revenues and natural gas cost expense. Nevertheless, increases and decreases in the cost of gas associated with system gas sales volumes and gross receipts tax expense (which are calculated as a percentage of revenues), with the same amount (excluding immaterial timing differences) included in revenues, have no direct effect on operating income. Therefore, management believes that contribution margin is a useful supplemental measure, along with the remaining operating expenses, for assessing the Company's and the Utilities' performance.

EARNINGS

This section contains discussion and analysis of the results for the year ended September 30, 2022 compared to the results for the year ended September 30, 2021. The discussion and analysis of the results for the year ended September 30, 2021 compared to the results of the year ended September 30, 2020 can be found in Part II, Item 7 of Spire Inc.'s fiscal 2021 Annual Report on Form 10-K, filed with the U.S. Securities and Exchange Commission (SEC) on November 22, 2021.

Overview

The past two years have offered numerous challenges. During severe winter weather in fiscal 2021, we were successful in providing safe, reliable service for our service areas in addition to driving value from investments in transportation and storage capacity we made at Spire Marketing. With regard to the Spire STL Pipeline, while operating under a temporary certificate, we continue to work with regulators and constituents regarding obtaining a permanent certificate. As discussed in Note 15, Regulatory Matters, of the Notes to Financial Statements in Item 8, we also received an order in our 2021 Missouri rate review which was inconsistent with precedent established by the MoPSC in prior rate cases.

Against this backdrop, the Company continued the important work of upgrading our Utilities' infrastructure to make our system safer, more reliable and environmentally sustainable. We also further deployed technology, including ultrasonic meters, to improve our service operations and deliver on improved experience for the homes and business we serve.

On the Gas Utility regulatory front, we continue to make progress. Spire Missouri filed a new general rate case on April 1, 2022, seeking full recovery of its updated cost of service, deferred overhead costs, and increased capital investment, as well as a fair and reasonable rate of return. The filing requested a $152 million revenue increase, reflecting a $3.4 billion rate base and a rate of return based on a requested return on equity of 10.5% and a 55% equity capitalization. After local public hearings were completed, the parties reached a Full Unanimous Stipulation and Agreement to resolve all issues in the case which was filed with the MoPSC on November 4, 2022. A hearing regarding this stipulation is currently set for November 18.

This fiscal year also saw progress in Spire's midstream operations. Spire Storage received FERC approval to expand capacity and increase pipeline connectivity at certain of Spire Storage's natural gas storage facilities in Wyoming. On August 26, 2022, the Company announced that capital expenditures in support of this project will total $195.0 through fiscal years 2023 into 2025.

The following sections present and discuss the financial metrics in total and by registrant and segment.

Spire

The following tables reconcile the Company's net economic earnings to the most comparable GAAP number, net income.

	Gas Utility	Gas Marketing	Other	Consol-idated	Per Diluted Share**
Year Ended September 30, 2022					
Net Income (Loss) [GAAP]	$ 198.6	$ 35.6	$ (13.4)	$ 220.8	$ 3.95
Adjustments, pre-tax:					
Fair value and timing adjustments	—	(11.4)	—	(11.4)	(0.22)
Income tax effect of adjustments*	4.1	2.8	—	6.9	0.13
Net Economic Earnings (Loss) [Non-GAAP]	$ 202.7	$ 27.0	$ (13.4)	$ 216.3	$ 3.86
Year Ended September 30, 2021					
Net Income (Loss) [GAAP]	$ 237.2	$ 44.8	$ (10.3)	$ 271.7	$ 4.96
Adjustments, pre-tax:					
Missouri regulatory adjustments	(9.0)	—	—	(9.0)	(0.17)
Fair value and timing adjustments	0.3	3.0	—	3.3	0.06
Acquisition, divestiture and restructuring activities	—	—	(1.3)	(1.3)	(0.02)
Income tax effect of adjustments*	2.1	(0.8)	0.3	1.6	0.03
Net Economic Earnings (Loss) [Non-GAAP]	$ 230.6	$ 47.0	$ (11.3)	$ 266.3	$ 4.86
Year Ended September 30, 2020					
Net Income (Loss) [GAAP]	$ 213.6	$ 7.0	$ (132.0)	$ 88.6	$ 1.44
Adjustments, pre-tax:					
Impairments	—	—	148.6	148.6	2.89
Fair value and timing adjustments	(0.3)	2.8	—	2.5	0.05
Income tax effect of adjustments*	0.1	(0.7)	(31.3)	(31.9)	(0.62)
Net Economic Earnings (Loss) [Non-GAAP]	$ 213.4	$ 9.1	$ (14.7)	$ 207.8	$ 3.76

* Income tax effect is calculated by applying federal, state and local income tax rates applicable to ordinary income to the amounts of the pre-tax reconciling items and then adding any estimated effects of enacted state or local income tax laws for periods before the related effective date and, in the case of fiscal 2022, includes the $4.1 Spire Missouri regulatory adjustment discussed below.

** Net economic earnings per share is calculated by replacing consolidated net income with consolidated net economic earnings in the GAAP diluted earnings per share calculation, which includes reductions for cumulative preferred dividends and participating shares.

Reconciliations of contribution margin to the most directly comparable GAAP measure are shown below.

	Gas Utility	Gas Marketing	Other	Eliminations	Consolidated
Year Ended September 30, 2022					
Operating Income	$ 339.9	$ 46.9	$ 21.4	$ —	$ 408.2
Operation and maintenance expenses	413.3	14.6	37.1	(15.4)	449.6
Depreciation and amortization	227.9	1.4	8.0	—	237.3
Taxes, other than income taxes	176.2	0.6	2.7	—	179.5
Less: Gross receipts tax expense	(109.6)	(0.2)	—	—	(109.8)
Contribution Margin [Non-GAAP]	1,047.7	63.3	69.2	(15.4)	1,164.8
Natural gas costs	788.8	171.4	—	(36.3)	923.9
Gross receipts tax expense	109.6	0.2	—	—	109.8
Operating Revenues	$ 1,946.1	$ 234.9	$ 69.2	$ (51.7)	$ 2,198.5

	Gas Utility	Gas Marketing	Other	Eliminations	Consolidated
Year Ended September 30, 2021					
Operating Income	$ 374.0	$ 58.5	$ 17.7	$ —	$ 450.2
Operation and maintenance expenses	422.2	17.1	40.2	(13.7)	465.8
Depreciation and amortization	204.4	1.2	7.5	—	213.1
Taxes, other than income taxes	157.0	0.9	2.2	—	160.1
Less: Gross receipts tax expense	(93.9)	(0.1)	—	—	(94.0)
Contribution Margin [Non-GAAP]	1,063.7	77.6	67.6	(13.7)	1,195.2
Natural gas costs	961.7	18.8	0.1	(34.3)	946.3
Gross receipts tax expense	93.9	0.1	—	—	94.0
Operating Revenues	$ 2,119.3	$ 96.5	$ 67.7	$ (48.0)	$ 2,235.5

	Gas Utility	Gas Marketing	Other	Eliminations	Consolidated
Year Ended September 30, 2020					
Operating Income (Loss)	$ 334.3	$ 9.3	$ (137.2)	$ —	$ 206.4
Operation and maintenance expenses	421.3	11.8	38.2	(12.7)	458.6
Depreciation and amortization	189.7	0.6	7.0	—	197.3
Taxes, other than income taxes	146.5	1.1	0.8	—	148.4
Impairment loss	—	—	148.6	—	148.6
Less: Gross receipts tax expense	(91.1)	(0.4)	—	—	(91.5)
Contribution Margin [Non-GAAP]	1,000.7	22.4	57.4	(12.7)	1,067.8
Natural gas costs	660.2	65.1	0.4	(29.6)	696.1
Gross receipts tax expense	91.1	0.4	—	—	91.5
Operating Revenues	$ 1,752.0	$ 87.9	$ 57.8	$ (42.3)	$ 1,855.4

Select changes from the year ended September 30, 2021 to the year ended September 30, 2022 are summarized in the following table and discussed below.

Changes from FY21 to FY22	**Gas Utility**	**Gas Marketing**	**Other, Net of Eliminations**	**Consolidated**
Net Income	$ (38.6)	$ (9.2)	$ (3.1)	$ (50.9)
Net Economic Earnings [Non-GAAP]	(27.9)	(20.0)	(2.1)	(50.0)
Operating Revenues	(173.2)	138.4	(2.2)	(37.0)
Contribution Margin [Non-GAAP]	(16.0)	(14.3)	(0.1)	(30.4)
Operating Expenses	(8.9)	(2.5)	(4.8)	(16.2)
Interest Expense				13.2
Income Tax				(9.6)

The increase in interest expense was primarily driven by higher levels of short-term borrowings in fiscal 2022, combined with the impact of net long-term debt issuances and higher average short-term interest rates. Short-term rates averaged 1.1% in fiscal 2022 compared to 0.4% for fiscal 2021.

The reduction in income taxes was primarily attributable to the lower pre-tax book income in 2022, partly offset by a $4.1 charge resulting from Tax Cuts and Jobs Act (TCJA) reconciliations from the 2021 Missouri rate order that was issued late in the first quarter of fiscal 2022.

Gas Utility

The $38.6 decrease in Gas Utility net income primarily reflects decreases of $29.2 and $5.3 at Spire Missouri and Spire Alabama, respectively, while the $27.9 decrease in net economic earnings for the segment reflects decreases of $18.5 and $5.3 at Spire Missouri and Spire Alabama, respectively. These results are described in further detail below.

The decrease in Gas Utility operating revenues for fiscal 2022 was attributable to the following factors:

Spire Missouri – Fiscal 2021 OFO charges	$ (195.8)
Spire Missouri – Off-system sales and capacity release	(120.1)
Spire Missouri and Spire Alabama – Volumetric usage (net of weather mitigation)	(9.9)
Spire Missouri and Spire Alabama – Higher PGA/GSA gas cost recoveries	99.9
Spire Missouri – 2021 rate order effects	18.1
Spire Missouri and Spire Alabama – Higher gross receipts taxes	15.7
Spire Alabama – Off-system sales and capacity release	9.8
Spire Alabama – RSE: net adjustments	4.3
All other factors	4.8
Total Variation	$ (173.2)

The decrease in revenues was driven primarily by a $199.8 decrease in Spire Missouri gas costs (including $195.8 of cover charges and OFO penalties to certain wholesale customers in the prior year), a $120.1 decrease in Spire Missouri off-system sales, and higher segment weather/volumetric impacts of $9.9. These negative impacts were partly offset by higher PGA/GSA gas cost recoveries of $99.9, an $18.1 increase in revenues as a result of the Spire Missouri 2021 rate order, higher segment gross receipts taxes of $15.7, a $9.8 increase in Spire Alabama off-system sales, and a $4.3 increase in revenues due to Spire Alabama's rate adjustments under the RSE mechanism.

The year-over-year decrease in Gas Utility contribution margin was attributable to the following factors:

Spire Missouri – Off-system sales and capacity release	$	(26.3)
Spire Missouri and Spire Alabama – Volumetric usage (net of weather mitigation)		(9.2)
Spire Missouri – 2021 rate order effects		18.1
Spire Alabama – RSE: net adjustments		3.8
Spire Alabama – Off-system and capacity release		1.5
All other factors		(3.9)
Total Variation	$	(16.0)

The contribution margin decrease resulted primarily from lower Missouri off-system sales, Spire Missouri and Spire Alabama volumetric impacts of $9.2, partly offset by an $18.1 increase resulting from the 2021 Missouri rate order, Spire Alabama rate adjustments under the RSE mechanism, and higher volumetric margins. The lower off-system sales and volumetric impacts were primarily the result of the extreme weather conditions from Winter Storm Uri in February 2021.

Reported O&M expenses decreased $8.9. O&M decreased by $9.8 after excluding the impacts of the Non-service Cost Transfer of $4.4, the $9.0 attributable to the Missouri Supreme Court ruling that partially reversed 2018 rate order pension cost disallowances, and $3.7 due to one-time cost adjustments relating to stipulations settled in the 2021 Spire Missouri rate order. This decrease is due primarily to lower employee-related costs and lower bad debt expense. Depreciation and amortization expenses for the year ended September 30, 2022 increased $24.2 from the prior year, principally the result of continued infrastructure capital spending, with $16.1 of the increase attributable to Spire Missouri and $4.7 attributable to Spire Alabama. Included in the Spire Missouri increase is a $3.4 charge pertaining to meter cost recovery that was disallowed by the MoPSC. Taxes, other than income taxes, increased $19.2, and were driven by the higher pass-through gross receipts taxes mentioned earlier, combined with higher property taxes resulting from the continued infrastructure build-out by the utilities.

Gas Marketing

Both net income and net economic earnings reflect the strong operating results in the prior year, driven by storage positions that resulted in optimization of market conditions in the second quarter of fiscal 2021 due to extreme weather as a result of Winter Storm Uri. Current year incremental optimization of storage and transportation assets in the Southeast during the third and fourth quarters of fiscal 2022 and favorable fair value adjustments only partly offset the benefits from the extreme weather in the prior year.

The variance in revenues primarily reflects higher commodity pricing in fiscal 2022.

Gas Marketing contribution margin decreased $14.3 from the same period last year, driven principally by strong second quarter results in fiscal 2021. During the second quarter of fiscal 2021, the February cold weather events drove significantly higher regional basis differentials and volumes, which were only partly offset by favorable year-over-year fair value adjustments of $14.4 and incremental optimization of storage and transportation assets in the Southeast during the third and fourth quarters of fiscal 2022.

Other

The Company's other non-utility activities generated a $3.1 higher net loss for fiscal 2022. Included in those results were higher interest and corporate costs in the current year. Other operating revenue increased $1.5, driven principally by Spire STL Pipeline and Spire Storage. Other operating expenses were $3.1 lower than the prior year, primarily reflecting lower current year operating expenses at Spire Storage and STL Pipeline.

Spire Missouri

	Year Ended September 30,	
	2022	2021
Operating Income	$ **204.0**	$ **228.6**
Operation and maintenance expenses	255.7	261.1
Depreciation and amortization	145.3	129.2
Taxes, other than income taxes	129.0	110.9
Less: Gross receipts tax expense	(79.6)	(64.3)
Contribution Margin [Non-GAAP]	**654.4**	**665.5**
Natural gas costs	587.0	786.8
Gross receipts tax expense	79.6	64.3
Operating Revenues	$ **1,321.0**	$ **1,516.6**
Net Income	$ **114.9**	$ **144.1**

The $195.6 decrease in operating revenues reflects a $120.1 decrease in 0ff-system sales and lower gas costs of $109.5 (as commodity cost recovery increases in the current year of $86.3 were more than offset by last year's $195.8 of cover charges and OFO penalties to certain wholesale customers). Partly offsetting these negative impacts were an $18.1 increase in operating revenues due to the 2021 Missouri rate order, a $15.3 increase in gross receipts taxes, and a $3.4 increase in volumetric impacts as underlying increases in economic activity more than offset the impact of warmer weather in the current year.

Temperatures in Spire Missouri's service areas during fiscal 2022 were 5.7% warmer than during fiscal 2021 and 9.5% warmer than normal. The Spire Missouri total system volume sold and transported was 1,602.8 million centum of cubic feet (CCF) for the year ended September 30, 2022, compared with 1,666.9 million CCF last year. Total off-system volume sold and transported was 19.1 million CCF for fiscal 2022, compared with 21.9 million for fiscal 2021.

Contribution margin decreased $11.1 from the prior year. The variance was attributable to a $26.3 decrease in off-system sales and $2.0 lower volumetric margins (both principally due to the extreme weather in February of the prior year), which were only partly offset by the previously mentioned $18.1 increase relating to the 2021 Missouri rate order.

Excluding the Non-service Cost Transfer of $3.5, the Missouri Supreme Court ruling totaling $9.0 and the $3.7 due to one-time cost adjustments relating to stipulations settled in the 2021 Spire Missouri rate order discussed above, O&M expenses during the year ended September 30, 2022, decreased $7.2 from last year. The decrease in O&M was driven by lower employee-related costs. Depreciation increased by $16.1 as a result of continuing capital investment and a $3.4 charge pertaining to disallowed meter cost recovery by the MoPSC. Taxes, other than income taxes, increased $18.1, driven by the higher pass-through gross receipts taxes and higher property taxes resulting from the continued infrastructure build-out.

Spire Missouri's other expense was $2.0 lower, as the increase of $3.5 due primarily to the Non-service Cost Transfer expense and decreases in the fair value of investments associated with non-qualified employee benefit plans reflecting market conditions were more than offset by miscellaneous income. Interest expense increased $10.6, reflecting higher levels of long-term debt and higher short-term interest rates. Income tax expense for the current year was lower by $4.0, as the impact of lower pre-tax book income was partly offset by a $4.1 charge resulting from TCJA reconciliations from the 2021 Missouri rate order that was completed late in the first quarter of fiscal 2022.

Spire Alabama

	Year Ended September 30, 2022	2021
Operating Income	$ **112.6**	$ **117.0**
Operation and maintenance expenses	130.1	132.5
Depreciation and amortization	66.8	62.1
Taxes, other than income taxes	38.1	37.1
Less: Gross receipts tax expense	(25.5)	(25.1)
Contribution Margin [Non-GAAP]	**322.1**	**323.6**
Natural gas costs	161.5	145.3
Gross receipts tax expense	25.5	25.1
Operating Revenues	$ **509.1**	$ **494.0**
Net Income	$ **68.5**	$ **73.8**

The $15.1 increase in operating revenues reflects a $13.6 increase in gas cost recoveries pursuant to the GSA mechanism, off-system sales in the current year contributing $9.8 to revenue growth, and $4.3 higher net rate adjustments under the RSE mechanism. These favorable impacts were partly offset by a $13.3 reduction attributable to weather/volumetric impacts that were impacted by weather mitigation.

Temperatures in Spire Alabama's service area during fiscal 2022 were 4.1% warmer than during fiscal 2021 and 9.7% warmer than normal. Spire Alabama's total system volume sold and transported was 1,010.8 million CCF during the year ended September 30, 2022, compared with 1,009.4 million CCF during the prior year. Off-system sales volume for fiscal 2022 totaled 63.1 million CCF compared with 47.5 million CCF for fiscal 2021.

Contribution margin decreased $1.5, which was principally a result of unfavorable weather/volumetric impacts totaling $7.2. This negative impact was mostly offset by net favorable RSE adjustments of $3.8 and off-system sales contributing $1.5 in growth in fiscal 2022. Excluding the impact of the Non-Service Cost Transfer of $0.9, the decrease in O&M of $1.5 was driven by lower operations and employee-related costs. Depreciation expense was up $4.7 reflecting the continued infrastructure investments being made in the territory.

LIQUIDITY AND CAPITAL RESOURCES

Recent Cash Flows

	2022	2021	2020
Net cash provided by operating activities	$ 55.0	$ 249.8	$ 469.9
Net cash used in investing activities	(546.7)	(622.0)	(631.6)
Net cash provided by financing activities	500.9	379.4	160.0

Net cash provided by operating activities decreased $194.8 from 2021 to 2022 and decreased $220.1 from 2020 to 2021. In addition to the changes in net income between the respective periods (discussed above), the remaining changes were related to regulatory timing and fluctuations in working capital items, as discussed below in the Future Cash Requirements section. More specifically, when looking at the change from 2020 to 2021, the large increase in accounts receivable was due to the February 2021 cold weather event and the related delayed collections. In addition, this significant cold weather event impacted other areas, including increased inventories to ensure supply and increased accounts payable as related gas costs had risen. For more information, see the discussion of Spire Missouri's Operational Flow Order in Note 15, Regulatory Matters, of the Notes to Financial Statements in Item 8.

In fiscal 2022, the Company's net cash used in investing activities was $75.3 less than in fiscal 2021, primarily driven by a $72.6 decrease in capital expenditures. The drivers of the lower capital expenditures were a $61.8 spending decline in the Utilities, a $8.1 decline for Spire Storage, and a slight decline at Spire STL Pipeline.

In fiscal 2021, the Company used $9.6 less cash in investing activities than in fiscal 2020, primarily driven by a $13.6 decrease in capital expenditures. The primary driver of the lower capital expenditures was a $53.3 decline related to Spire STL Pipeline and Spire Storage, largely offset by a $42.6 capital spending increase at Gas Utility, where the focus remained on infrastructure upgrades and new business development.

Net cash provided by financing activities was up $121.5 in fiscal 2022 compared to fiscal 2021. Current year short-term debt, net issuances were $365.5, or $341.5 higher than in fiscal 2021. In addition, the combination of lower net repayments of long-term debt ($59.6) and higher cash generated from the issuance of common stock ($50.9) in fiscal 2022 contributed $110.5 to the year-over-year increase. A significant offset to these increases was a $329.1 decline in cash generated from the issuance of long-term debt, coupled with $8.7 higher common stock dividend payments.

Net cash provided by financing activities was up $219.4 in fiscal 2021 compared to fiscal 2020. In fiscal 2021, long-term debt issuances were $629.1, or $119.1 higher than in fiscal 2020, and the combination of lower net repayments of both long-term and short-term debt in fiscal 2021 contributed $150.8 to the year-over-year increase. Partially offsetting these increases was a $40.1 decline in cash generated from common stock issuances and $5.2 higher common stock dividend payments.

Future Cash Requirements

The Company’s short-term borrowing requirements typically peak during colder months when the Utilities borrow money to cover the lag between when they purchase natural gas and when their customers pay for that gas. Changes in the wholesale cost of natural gas (including cash payments for margin deposits associated with Spire Missouri’s use of natural gas derivative instruments), variations in the timing of collections of gas cost under the Utilities’ PGA clauses and GSA riders, the seasonality of accounts receivable balances, and the utilization of storage gas inventories cause short-term cash requirements to vary during the year and from year to year, and may cause significant variations in the Company’s cash provided by or used in operating activities.

Spire’s material cash requirements as of September 30, 2022, are related to capital expenditures, principal and interest payments on long-term debt, natural gas purchase obligations, and dividends.

Total Company capital expenditures are planned to be $700 for fiscal 2023, though Spire had purchase commitments for only a small portion of these as of September 30, 2022.

As detailed in Note 6, Long-Term Debt, of the Notes to Financial Statements in Item 8, $281.2 of the total $3,258.9 principal amount is due in fiscal 2023. Using each long-term debt instrument’s stated maturity and fixed rates or variable rates as of September 30, 2022, interest payments are projected to total $1,560.2, of which $116.2 is due in fiscal 2023.

Spire’s natural gas purchase obligations totaled $2,107.1, including $946.8 for fiscal 2023, representing the minimum payments required under existing natural gas transportation and storage contracts and natural gas supply agreements. The amounts reflect fixed obligations as well as obligations to purchase natural gas at future market prices, calculated using forward market prices as of September 30, 2022. Each of the Utilities generally recovers costs related to its purchases, transportation and storage of natural gas through the operation of its PGA clause or GSA rider, subject to prudence review by the appropriate regional public service commission. Additional contractual commitments are generally entered into prior to or during the heating season.

Spire dividends declared and payable as of September 30, 2022, totaled $41.2, while annualized dividends based on the regular quarterly amounts declared on November 10, 2022, are estimated at $165.9.

Source of Funds

It is management’s view that the Company, Spire Missouri and Spire Alabama have adequate access to capital markets and will have sufficient capital resources, both internal and external, to meet anticipated requirements.

The Company's, Spire Missouri's and Spire Alabama's access to capital markets, including the commercial paper market, and their respective financing costs, may depend on the credit rating of the entity that is accessing the capital markets. Their debt is rated by two rating agencies: Standard & Poor's Corporation ("S&P") and Moody's Investors Service ("Moody's"). As of September 30, 2022, the debt ratings of the Company, Spire Missouri and Spire Alabama (shown in the following table) remain at investment grade with a stable outlook (other than Moody's negative outlook for Spire Missouri debt).

	S&P	Moody's
Spire Inc. senior unsecured long-term debt	BBB+	Baa2
Spire Inc. preferred stock	BBB	Ba1
Spire Inc. short-term debt	A-2	P-2
Spire Missouri senior secured long-term debt	A	A1
Spire Alabama senior unsecured long-term debt	A-	A2

Cash and Cash Equivalents

Bank deposits were used to support working capital needs of the business. Spire had no temporary cash investments as of September 30, 2022 or 2021.

Short-term Debt

The Company's short-term cash requirements can be met through the sale of commercial paper or the use of a revolving credit facility. For information about these resources, see Note 7, Notes Payable and Credit Agreements, of the Notes to Financial Statements in Item 8 and "Interest Rate Risk" under "Market Risk" below.

Long-term Debt and Equity

At September 30, 2022, including the current portion but excluding unamortized discounts and debt issuance costs, Spire had long-term debt totaling $3,258.9, of which $1,648.0 was issued by Spire Missouri, $575.0 was issued by Spire Alabama, and $205.9 was issued by other subsidiaries. For more information about long-term debt, see Note 6 of the Notes to Financial Statements in Item 8 and "Interest Rate Risk" under "Market Risk" below.

On December 7, 2021, pursuant to its registration statement on Form S-3 filed with the SEC, Spire Missouri issued $300.0 of first mortgage bonds due December 2, 2024, secured equally with all its other first mortgage bonds. Interest is payable quarterly in arrears at a floating rate based on the compounded secured overnight financing rate plus 50 basis points, with a maximum rate of the lesser of 8% or the maximum rate then permitted by applicable law.

Effective March 5, 2022, Spire Missouri was authorized by the MoPSC to issue conventional term loans, first mortgage bonds, unsecured debt, preferred stock and common stock in an aggregate amount of up to $800.0 for financings placed any time before December 31, 2024. As of September 30, 2022, the entire amount remained available under this authorization. Spire Alabama has no standing authority to issue long-term debt and must petition the APSC for each planned issuance.

After fiscal year end, on October 13, 2022, Spire Alabama issued $90.0 of notes due October 15, 2029, bearing interest at 5.32% and $85.0 of notes due October 15, 2032, bearing interest at 5.41%. Interest is payable semi-annually. The notes are senior unsecured obligations and rank equal in right to payment with all other senior unsecured indebtedness of Spire Alabama. Also on October 13, 2022, Spire Gulf issued $30.0 of first mortgage bonds due October 15, 2037, bearing interest at 5.61% payable semi-annually. The bonds rank equal in right to payment with the other first mortgage bonds issued by Spire Gulf. The bonds were issued under a supplemental indenture with collateral fall away provisions whereby, under certain conditions, Spire Gulf may elect to exchange the bonds, which are secured, for unsecured notes.

Spire has a shelf registration statement on Form S-3 on file with the SEC for the issuance and sale of up to 250,000 shares of common stock under its Dividend Reinvestment and Direct Stock Purchase Plan. There were 158,535 and 153,190 shares at September 30, 2022 and November 11, 2022, respectively, remaining available for issuance under this Form S-3. Spire and Spire Missouri also have a universal shelf registration statement on Form S-3 on file with the SEC for the issuance of various equity and debt securities, which expires on May 9, 2025.

On February 6, 2019, Spire entered into an "at-the-market" (ATM) equity distribution agreement pursuant to which the Company may offer and sell, from time to time, shares of its common stock pursuant to Spire's universal shelf registration statement and a prospectus supplement. Under this program, a total of 626,249 shares with an aggregate offering price of $47.8 were issued in fiscal 2019 and 2020, and 354,000 shares with an aggregate offering price of $23.5 were issued in the second quarter of fiscal 2022. On April 28, 2022, Spire's Board of Directors approved a new authorization for the sale of additional shares with an aggregate offering price of up to $200.0 before the May 2025 expiration of the new universal shelf registration statement on Form S-3 filed in May 2022, under which a total of 365,625 shares with an aggregate offering price of $27.7 were issued in the third quarter of fiscal 2022.

In February 2021, Spire issued 3.5 million equity units for an aggregate stated amount of $175.0, resulting in net proceeds of $169.3 after underwriting fees and other issuance costs. See Note 5, Shareholders' Equity, of the Notes to Financial Statements in Item 8 for additional discussion of these equity units.

Including the current portion of long-term debt, the Company's long-term consolidated capitalization consisted of 46% equity at September 30, 2022 and 47% equity at September 30, 2021. For more information about equity, see Note 5 of the Notes to Financial Statements in Item 8.

ENVIRONMENTAL MATTERS

The Utilities and other Spire subsidiaries own and operate natural gas distribution, transmission and storage facilities, the operations of which are subject to various environmental laws, regulations and interpretations. While environmental issues resulting from such operations arise in the ordinary course of business, such issues have not materially affected the Company's, Spire Missouri's or Spire Alabama's financial position and results of operations. As environmental laws, regulations and their interpretations change, however, the Company and the Utilities may be required to incur additional costs. For information relative to environmental matters, see Contingencies in Note 16 of the Notes to Financial Statements in Item 8.

REGULATORY MATTERS

In May and July 2021, the U.S. Department of Homeland Security's Transportation Security Administration issued security directives that included several new cybersecurity requirements for critical pipeline owners and operators. Among these requirements is the implementation of specific mitigation measures to protect against ransomware attacks and other known threats to information and operational technology systems; development and implementation of a cybersecurity contingency and recovery plan; and performance of a cybersecurity architecture design review. We are currently implementing several of these directives and evaluating the potential effect of several others on our operations and facilities, as well as the potential cost of implementation, and will continue to monitor for any clarifications or amendments to these directives. We are also engaged in a continuous program of testing and updating our cybersecurity measures.

For discussions of other regulatory matters for Spire, Spire Missouri, and Spire Alabama, see Note 15, Regulatory Matters, of the Notes to Financial Statements in Item 8.

ACCOUNTING PRONOUNCEMENTS

The Company, Spire Missouri and Spire Alabama have evaluated recently issued accounting standards and concluded that none will have a material impact on their financial position or results of operations upon adoption.

CRITICAL ACCOUNTING ESTIMATES

Our discussion and analysis of our financial condition, results of operations, liquidity and capital resources are based upon our financial statements, which have been prepared in accordance with GAAP, which requires that we make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. We evaluate our estimates on an ongoing basis. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates. We believe the following represent the more significant items requiring the use of judgment and estimates in preparing our financial statements:

Regulatory Accounting – The Utilities account for their regulated operations in accordance with FASB Accounting Standards Codification Topic 980, *Regulated Operations*. The provisions of this accounting guidance require, among other things, that financial statements of a rate-regulated enterprise reflect the actions of regulators, where appropriate. These actions may result in the recognition of revenues and expenses in time periods that are different than non-rate-regulated enterprises. When this occurs, costs are deferred as assets in the balance sheet (regulatory assets) and recorded as expenses when those amounts are reflected in rates. Also, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for recovery of costs that are expected to be incurred in the future (regulatory liabilities). Management believes that the current regulatory environment supports the continued use of these regulatory accounting principles and that all regulatory assets and regulatory liabilities are recoverable or refundable through the regulatory process. For Spire Missouri and Spire Alabama, management believes the following represent the more significant items recorded through the application of this accounting guidance:

> **PGA Clause** – Spire Missouri's PGA clauses allows it to flow through to customers, subject to a prudence review by the MoPSC, the cost of purchased gas supplies, including the costs, cost reductions and related carrying costs associated with the use of natural gas derivative instruments to hedge the purchase price of natural gas. The difference between actual costs incurred and costs recovered through the application of the PGA clauses are recorded as regulatory assets and regulatory liabilities that are recovered or refunded in a subsequent period. The PGA clauses also permit the application of carrying costs to all over- or under-recoveries of gas costs, including costs and cost reductions associated with the use of derivative instruments, and also provide for a portion of income from off-system sales and capacity release revenues to be flowed through to customers.
>
> **GSA Rider** – Spire Alabama's rate schedules for natural gas distribution charges contain a GSA rider, established in 1993, which permits the pass-through to customers of changes in the cost of gas supply. Spire Alabama's tariff provides a temperature adjustment mechanism, also included in the GSA, that is designed to moderate the impact of departures from normal temperatures on Spire Alabama's earnings. The temperature adjustment applies primarily to residential, small commercial and small industrial customers. Other non-temperature weather related conditions that may affect customer usage are not included in the temperature adjustment. In prior years, Spire Alabama entered into cash flow derivative commodity instruments to hedge its exposure to price fluctuations on its gas supply. Spire Alabama recognizes all derivatives at fair value as either assets or liabilities on the balance sheet. Any realized gains or losses are passed through to customers using the mechanisms of the GSA rider in accordance with Spire Alabama's APSC approved tariff and are recognized as a regulatory asset or regulatory liability. All derivative commodity instruments in a gain position are valued on a discounted basis incorporating an estimate of performance risk specific to each related counterparty. Derivative commodity instruments in a loss position are valued on a discounted basis incorporating an estimate of performance risk specific to Spire Alabama. Spire Alabama currently has no active gas supply derivative positions.
>
> **ISRS** – The ISRS allows Spire Missouri expedited recovery for its investment to upgrade its infrastructure and enhance its safety and reliability without the necessity of a formal rate case. Spire Missouri records ISRS revenues as authorized by the MoPSC and estimates the probability and amount of any refunds based on commission precedent, current legal rulings, the opinion of legal counsel, and other considerations.
>
> **Non-operational Overhead Costs** – As a result of certain MoPSC orders, Spire Missouri ceased capitalization of non-operational overhead costs but deferred such costs into a regulatory asset for future review by the MoPSC. Management believes it is probable that Spire Missouri will ultimately be allowed to recover these deferred costs.

For more information, see Note 15, Regulatory Matters, of the Notes to Financial Statements in Item 8.

Employee Benefits and Postretirement Obligations – Pension and postretirement obligations are calculated by actuarial consultants that utilize several statistical factors and other assumptions provided by management related to future events, such as discount rates, returns on plan assets, compensation increases, and mortality rates. For the Utilities, the amount of expense recognized and the amounts reflected in other comprehensive income are dependent upon the regulatory treatment provided for such costs, as discussed further below. Certain liabilities related to group medical benefits and workers' compensation claims, portions of which are self-insured and/or contain "stop-loss" coverage with third-party insurers to limit exposure, are established based on historical trends.

The amount of net periodic pension and other postretirement benefit costs recognized in the financial statements related to the Utilities' qualified pension plans and other postretirement benefit plans is based upon allowances, as approved by the MoPSC (for Spire Missouri) and as approved by the APSC (for Spire Alabama). The allowances have been established in the rate-making process for the recovery of these costs from customers. The differences between these amounts and actual pension and other postretirement benefit costs incurred for financial reporting purposes are deferred as regulatory assets or regulatory liabilities. GAAP also requires that changes that affect the funded status of pension and other postretirement benefit plans, but that are not yet required to be recognized as components of pension and other postretirement benefit costs, be reflected in other comprehensive income. For the Utilities' qualified pension plans and other postretirement benefit plans, amounts that would otherwise be reflected in other comprehensive income are deferred with entries to regulatory assets or regulatory liabilities.

For more information, see Note 13, Pension Plans and Other Postretirement Benefits, of the Notes to Financial Statements in Item 8.

The tables below reflect the sensitivity of Spire's plans to potential changes in key assumptions:

Pension Plan Benefits:

Actuarial Assumptions	Increase/ (Decrease)	Estimated Increase/ (Decrease) to Projected Benefit Obligation	Estimated Increase/ (Decrease) to Annual Net Pension Cost*
Discount Rate	0.25%	$ (10.6)	$ 0.4
	(0.25)%	11.1	(0.4)
Expected Return on Plan Assets	0.25%	—	(1.2)
	(0.25)%	—	1.2
Rate of Future Compensation Increase	0.25%	0.7	0.2
	(0.25)%	(0.7)	(0.2)

Postretirement Benefits:

Actuarial Assumptions	Increase/ (Decrease)	Estimated Increase/ (Decrease) to Projected Postretirement Benefit Obligation	Estimated Increase/ (Decrease) to Annual Net Postretirement Benefit Cost*
Discount Rate	0.25%	$ (2.8)	$ 0.1
	(0.25)%	2.9	(0.1)
Expected Return on Plan Assets	0.25%	—	(0.7)
	(0.25)%	—	0.7

* Excludes the impact of regulatory deferral mechanism. See Note 13, Pension Plans and Other Postretirement Benefits, of the Notes to Financial Statements in Item 8 for information regarding the regulatory treatment of these costs.

Impairment of Long-lived Assets – Long-lived assets classified as held and used are evaluated for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Whether impairment has occurred is determined by comparing the estimated undiscounted cash flows attributable to the assets with the carrying value of the assets. If the carrying value exceeds the undiscounted cash flows, the Company recognizes an impairment charge equal to the amount of the carrying value that exceeds the estimated fair value of the assets. In the period in which the Company determines an asset meets held-for-sale criteria, an impairment charge is recorded to the extent the book value exceeds its fair value less cost to sell.

On July 1, 2020, Spire's Board of Directors, based upon the recommendation of senior management, revised the development plan for Spire Storage, resulting in an impairment charge of $140.8 related to Spire Storage assets in the quarter ended June 30, 2020. The revision was driven by the realization that a longer time horizon will be required for optimization and positioning of the storage facility to serve energy markets in the western United States. Among other factors, evaluations of the continuing evolution of market dynamics in the region led management to update models of various development alternatives. Separately in the quarter ended June 30, 2020, Spire recorded impairment charges totaling $7.8 related to two commercial compressed natural gas fueling stations as a result of revised projections reflecting lower diesel prices and slower conversions of Class 8 vehicles. The fair values used in measuring the impairment charges were determined with an expected present value technique using a discounted cash flow method under an income approach. Our impairment loss calculations required management to make assumptions and to apply judgment in order to estimate fair values of the assets. This involved estimating cash flows, useful lives, and current market value for similar assets and selecting a discount rate that reflects the risk inherent in future cash flows. Cash flow projections were based on assumptions about future market demand and achievement of certain operational capabilities. Assumptions were selected from a range of reasonably possible amounts and were supported by relevant and reliable data. However, if actual results are not consistent with our estimates and assumptions, we may be exposed to additional impairments that could be material. We do not believe there is a reasonable likelihood that there will be a material change in the estimates or assumptions we use to calculate asset impairment losses.

As discussed in Note 15, Regulatory Matters, of the Notes to Financial Statements in Item 8, the Spire STL Pipeline is operating under temporary certificates while the FERC considers approval of a new permanent certificate. While uncertainty exists, management has evaluated the facts in accordance with ASC 360 and concluded that the related assets have not become impaired.

Income Taxes – Income tax calculations require estimates due to book-tax differences, estimates with respect to regulatory treatment of certain items, and uncertainty in the interpretation of tax laws and regulations. Critical assumptions and judgments also include projections of future taxable income to determine the ability to utilize net operating losses and credit carryforwards prior to their expiration. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. Management regularly assesses financial statement tax provisions to identify any change in regulatory treatment or tax related estimates and assumptions that could have a material impact on cash flows, financial position and/or results of operations. For more information, see Note 12, Income Taxes, of the Notes to Financial Statements in Item 8.

For further discussion of significant accounting policies, see Note 1, Summary of Significant Accounting Policies, of the Notes to Financial Statements in Item 8.

MARKET RISK

Commodity Price Risk

Gas Utility

The Utilities' commodity price risk, which arises from market fluctuations in the price of natural gas, is primarily managed through the operation of Spire Missouri's PGA clauses and Spire Alabama's GSA rider. The PGA clauses and GSA rider allows the Utilities to flow through to customers, subject to prudence review by the MoPSC and APSC, the cost of purchased gas supplies. Spire Missouri is allowed the flexibility to make up to three discretionary PGA changes during each year, in addition to its mandatory November PGA change, so long as such changes are separated by at least two months. Spire Missouri is able to mitigate, to some extent, changes in commodity prices through the use of physical storage supplies and regional supply diversity. Spire Alabama is allowed to make monthly changes to the GSA rate, but increases cannot exceed a 5% increase over the prior effective residential billing rate. The Utilities also have risk management policies that allow for the purchase of natural gas derivative instruments with the goal of managing its price risk associated with purchasing natural gas on behalf of its customers. These policies prohibit speculation. As of September 30, 2022, Spire Missouri had active natural gas derivative positions, but Spire Alabama did not. Costs and cost reduction, including carrying costs, associated with the use of natural gas derivative instruments are allowed to be passed on to customers through the operation of the PGA clauses or GSA rider. Accordingly, the Utilities do not expect any adverse earnings impact as a result of the use of these derivative instruments. However, the timing of recovery for cash payments related to margin requirements may cause short-term cash requirements to vary. For more information about the Utilities' natural gas derivative instruments, see Note 10, Derivative Instruments and Hedging Activities, of the Notes to Financial Statements in Item 8.

Gas Marketing

In the course of its business, Spire's non-regulated gas marketing subsidiary, Spire Marketing, enters into contracts to purchase and sell natural gas at fixed prices and natural gas index-based prices. Commodity price risk associated with these contracts has the potential to impact earnings and cash flows. To minimize this risk, Spire Marketing has a risk management policy that provides for daily monitoring of a number of business measures, including fixed price commitments. In accordance with the risk management policy, Spire Marketing manages the price risk associated with its fixed price commitments. This risk is currently managed either by closely matching the offsetting physical purchase or sale of natural gas at fixed-prices or through the use of natural gas futures, options and swap contracts traded on or cleared through the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE) to lock in margins. At September 30, 2022 and 2021, Spire Marketing's unmatched fixed-price positions were not material to Spire's financial position or results of operations.

As mentioned above, Spire Marketing uses natural gas futures, options and swap contracts traded on or cleared through the NYMEX and ICE to manage the commodity price risk associated with its fixed-price natural gas purchase and sale commitments. These derivative instruments may be designated as cash flow hedges of forecasted purchases or sales. Such accounting treatment, if elected, generally permits a substantial portion of the gain or loss to be deferred from recognition in earnings until the period that the associated forecasted purchase or sale is recognized in earnings. To the extent a hedge is effective, gains or losses on the derivatives will be offset by changes in the value of the hedged forecasted transactions. At September 30, 2022 and 2021, Spire Marketing had no designated cash flow hedges. Information about the fair values of Spire Marketing's exchange-traded/cleared natural gas derivative instruments is presented below:

	Derivative Fair Values	Cash Margin	Derivatives and Cash Margin
Net balance of derivative assets at September 30, 2021	$ 52.1	$ (39.3)	$ 12.8
Changes in fair value	43.3	—	43.3
Settlements/purchases - net	(84.8)	—	(84.8)
Changes in cash margin	—	54.5	54.5
Net balance of derivative assets at September 30, 2022	$ 10.6	$ 15.2	$ 25.8

	As of September 30, 2022				
Maturity by Fiscal Year	**Total**	**2023**	**2024**	**2025**	**2026**
Fair values of exchange-traded/cleared natural gas derivatives - net	$ 14.7	$ 12.5	$ 2.5	$ (0.3)	$ —
Fair values of basis swaps - net	(3.2)	(2.9)	(0.2)	(0.1)	—
Fair values of puts and calls - net	(1.9)	(1.9)	—	—	—
Position volumes:					
MMBtu - net (short) long futures/swap/option positions	84.1	50.3	19.5	13.0	1.3
MMBtu - net (short) long basis swap positions	(16.0)	(13.6)	(1.8)	(0.6)	—
MMBtu - net (short) puts and calls positions	(1.4)	(1.4)	—	—	—

Certain of Spire Marketing's physical natural gas derivative contracts are designated as normal purchases or normal sales, as permitted by GAAP. This election permits the Company to account for the contract in the period the natural gas is delivered. Contracts not designated as normal purchases or normal sales, including those designated as trading activities, are accounted for as derivatives with changes in fair value recognized in earnings in the periods prior to settlement.

Below is a reconciliation of the beginning and ending balances for physical natural gas contracts accounted for as derivatives, none of which will settle beyond fiscal 2023:

Net balance of derivative liabilities at September 30, 2021	$ (61.5)
Changes in fair value	101.0
Settlements	(48.4)
Net balance of derivative liabilities at September 30, 2022	$ (8.9)

For further details related to Spire Marketing's derivatives and hedging activities, see Note 10, Derivative Instruments and Hedging Activities, of the Notes to Financial Statements in Item 8.

Counterparty Credit Risk

Spire Marketing has concentrations of counterparty credit risk in that a significant portion of its transactions are with energy producers, utility companies and pipelines. These concentrations of counterparties have the potential to affect the Company's overall exposure to credit risk, either positively or negatively, in that each of these three groups may be affected similarly by changes in economic, industry or other conditions. Spire Marketing also has concentrations of credit risk with certain individually significant counterparties. To the extent possible, Spire Marketing enters into netting arrangements with its counterparties to mitigate exposure to credit risk. It is also exposed to credit risk associated with its derivative contracts designated as normal purchases and normal sales. Spire Marketing closely monitors its credit exposure and, although uncollectible amounts have not been significant, increased counterparty defaults are possible and may result in financial losses and/or capital limitations. For more information on these and other concentrations of credit risk, including how Spire Marketing manages these risks, see Note 11, Concentrations of Credit Risk, of the Notes to Financial Statements in Item 8.

Interest Rate Risk

The Company is subject to interest rate risk associated with its short-term debt issuances. Based on average short-term borrowings during fiscal 2022, an increase of 100 basis points in the underlying average interest rate for short-term debt would have caused an increase in interest expense (and a decrease in pre-tax earnings and cash flows) of approximately $7.5 on an annual basis. Portions of such an increase may be offset through the Utilities' application of PGA and GSA carrying costs. At September 30, 2022, Spire had fixed-rate long-term debt totaling $2,958.9, of which $1,348.0 was issued by Spire Missouri, $575.0 was issued by Spire Alabama, and $1,035.9 was issued by Spire and other subsidiaries. While the long-term debt issues are fixed-rate, they are subject to changes in fair value as market interest rates change. However, increases or decreases in fair value would impact earnings and cash flows only if the Company were to reacquire any of these issues in the open market prior to maturity. Under GAAP applicable to the Utilities' regulated operations, losses or gains on early redemptions of long-term debt would typically be deferred as regulatory assets or regulatory liabilities and amortized over a future period.

Refer to Note 10, Derivative Instruments and Hedging Activities, of the Notes to Financial Statements in Item 8 for additional details on the Company's interest rate swap transactions.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

For this discussion, see "Market Risk" in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.

Item 8. Financial Statements and Supplementary Data

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Management Reports on Internal Control over Financial Reporting

Spire Inc.

Management is responsible for establishing and maintaining adequate internal controls over financial reporting. Spire Inc.'s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risks that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Spire Inc.'s management, including its Chief Executive Officer and Chief Financial Officer, conducted an assessment of the effectiveness of Spire Inc.'s internal control over financial reporting as of September 30, 2022. In making this assessment, management used the criteria in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, management concluded that Spire Inc.'s internal control over financial reporting was effective as of September 30, 2022. Deloitte & Touche LLP, an independent registered public accounting firm, has issued an attestation report on Spire Inc.'s internal control over financial reporting, which is included herein.

Spire Missouri Inc.

Management is responsible for establishing and maintaining adequate internal controls over financial reporting. Spire Missouri Inc.'s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risks that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Spire Missouri Inc.'s management, including its Chief Executive Officer and Chief Financial Officer, conducted an assessment of the effectiveness of Spire Missouri Inc.'s internal control over financial reporting as of September 30, 2022. In making this assessment, management used the criteria in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, management concluded that Spire Missouri Inc.'s internal control over financial reporting was effective as of September 30, 2022.

Spire Alabama Inc.

Management is responsible for establishing and maintaining adequate internal controls over financial reporting. Spire Alabama Inc.'s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risks that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Spire Alabama Inc.'s management, including its Chief Executive Officer and Chief Financial Officer, conducted an assessment of the effectiveness of Spire Alabama Inc.'s internal control over financial reporting as of September 30, 2022. In making this assessment, management used the criteria in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, management concluded that Spire Alabama Inc.'s internal control over financial reporting was effective as of September 30, 2022.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Spire Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Spire Inc. and subsidiaries (the "Company") as of September 30, 2022, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2022, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended September 30, 2022, of the Company and our report dated November 16, 2022, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for their assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Reports on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP

St. Louis, Missouri
November 16, 2022

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Spire Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Spire Inc. and subsidiaries (the "Company") as of September 30, 2022 and 2021, the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows, for each of the three years in the period ended September 30, 2022, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of September 30, 2022 and 2021, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2022, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of September 30, 2022, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated November 16, 2022, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Matters – Impact of Rate Regulation on the Financial Statements – Refer to Note 15 to the financial statements

Critical Audit Matter Description

The Company accounts for their regulated operations in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 980, *Regulated Operations*. The provisions of this accounting guidance require, among other things, that financial statements of a rate-regulated enterprise reflect the actions of regulators, where appropriate. These actions may result in the recognition of revenues and expenses in time periods that are different than non-rate-regulated enterprises. When this occurs, costs are deferred as assets in the balance sheet (regulatory assets) and recorded as expenses when those amounts are reflected in rates. Also, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for recovery of costs that are expected to be incurred in the future (regulatory liabilities).

The Company is subject to rate regulation by the Missouri, Alabama, and Mississippi Public Service Commissions (the "Commissions"), which have jurisdiction with respect to the rates of natural gas companies within their respective geographies. The Company has stated that all regulatory assets and regulatory liabilities are recoverable or refundable through the regulatory process.

Accounting for the economics of rate regulation affects multiple financial statement line items, including property, plant, and equipment; regulatory assets and liabilities; operating revenues; and depreciation expense, and affects multiple disclosures in the Company's financial statements. There is a risk that the Commissions will not approve full recovery of the costs of providing utility service or recovery of all amounts invested in the utility business and a reasonable return on that investment. As a result, we identified the impact of rate regulation as a critical audit matter due to the high degree of subjectivity involved in assessing the impact of current and future regulatory orders on events that have occurred as of September 30, 2022, and the judgments made by management to support its assertions about impacted account balances and disclosures. Management judgments included assessing the likelihood of (1) recovery in future rates of incurred costs or (2) refunds to customers or future reduction in rates. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the Commissions, auditing these rate-impacted account balances and disclosures, and the related judgments, requires specialized knowledge of accounting for rate regulation due to the inherent complexities associated with the specialized rules related to accounting for the effects of cost-based regulation.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We tested the effectiveness of management's controls over evaluating the likelihood of (1) the recovery in future rates of costs incurred as property, plant, and equipment and deferred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We tested the effectiveness of management's controls over the initial recognition of amounts as property, plant, and equipment; regulatory assets or liabilities; and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments, in the financial statements.
- We read relevant regulatory orders issued by the Commissions for the Company in Missouri, Alabama, and Mississippi; regulatory statutes, interpretations, procedural memorandums, and filings made by interveners; and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances.
- We obtained from management the regulatory orders that support the probability of recovery, refund, and/or future reduction in rates for regulatory assets and liabilities and assessed management's assertion that amounts are probable of recovery, refund, or a future reduction in rates.

/s/ Deloitte & Touche LLP

St. Louis, Missouri
November 16, 2022

We have served as the Company's auditor since 1953.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholder and the Board of Directors of Spire Missouri Inc.

Opinion on the Financial Statements

We have audited the accompanying balance sheets of Spire Missouri Inc. (a wholly owned subsidiary of Spire Inc.) (the "Company")as of September 30, 2022 and 2021, the related statements of comprehensive income, shareholder's equity, and cash flows, for each of the three years in the period ended September 30, 2022, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of September 30, 2022 and 2021, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2022, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of their internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Matters – Impact of Rate Regulation on the Financial Statements – Refer to Note 15 to the financial statements

Critical Audit Matter Description

The Company accounts for their regulated operations in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 980, *Regulated Operations*. The provisions of this accounting guidance require, among other things, that financial statements of a rate-regulated enterprise reflect the actions of regulators, where appropriate. These actions may result in the recognition of revenues and expenses in time periods that are different than non-rate-regulated enterprises. When this occurs, costs are deferred as assets in the balance sheet (regulatory assets) and recorded as expenses when those amounts are reflected in rates. Also, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for recovery of costs that are expected to be incurred in the future (regulatory liabilities).

The Company is subject to rate regulation by the Missouri Public Service Commission (the "Commission"), which has jurisdiction with respect to the rates of natural gas companies within Missouri's geography. The Company has stated that all regulatory assets and regulatory liabilities are recoverable or refundable through the regulatory process.

Accounting for the economics of rate regulation affects multiple financial statement line items, including property, plant, and equipment; regulatory assets and liabilities; operating revenues; and depreciation expense, and affects multiple disclosures in the Company's financial statements. There is a risk that the Commission will not approve full recovery of the costs of providing utility service or recovery of all amounts invested in the utility business and a reasonable return on that investment. As a result, we identified the impact of rate regulation as a critical audit matter due to the high degree of subjectivity involved in assessing the impact of current and future regulatory orders on events that have occurred as of September 30, 2022, and the judgments made by management to support their assertions about impacted account balances and disclosures. Management judgments included assessing the likelihood of (1) recovery in future rates of incurred costs or (2) refunds to customers or future reduction in rates. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the Commission, auditing these rate-impacted account balances and disclosures, and the related judgments, requires specialized knowledge of accounting for rate regulation due to the inherent complexities associated with the specialized rules related to accounting for the effects of cost-based regulation.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commission included the following, among others:

- We tested the effectiveness of management's controls over evaluating the likelihood of (1) the recovery in future rates of costs incurred as property, plant, and equipment and deferred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We tested the effectiveness of management's controls over the initial recognition of amounts as property, plant, and equipment; regulatory assets or liabilities; and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments, in the financial statements.
- We read relevant regulatory orders issued by the Commission for the Company in Missouri; regulatory statutes, interpretations, procedural memorandums, and filings made by interveners; and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commission's treatment of similar costs under similar circumstances.
- We obtained from management the regulatory orders that support the probability of recovery, refund, and/or future reduction in rates for regulatory assets and liabilities and assessed management's assertion that amounts are probable of recovery, refund, or a future reduction in rates.

/s/ Deloitte & Touche LLP

St. Louis, Missouri
November 16, 2022

We have served as the Company's auditor since 1953.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholder and the Board of Directors of Spire Alabama Inc.

Opinion on the Financial Statements

We have audited the accompanying balance sheets of Spire Alabama Inc. (a wholly owned subsidiary of Spire Inc.) (the "Company") as of September 30, 2022 and 2021, the related statements of income, shareholder's equity, and cash flows, for each of the three years in the period ended September 30, 2022, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of September 30, 2022 and 2021, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2022, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of their internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Matters – Impact of Rate Regulation on the Financial Statements – Refer to Note 15 to the financial statements

Critical Audit Matter Description

The Company accounts for their regulated operations in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 980, *Regulated Operations*. The provisions of this accounting guidance require, among other things, that financial statements of a rate-regulated enterprise reflect the actions of regulators, where appropriate. These actions may result in the recognition of revenues and expenses in time periods that are different than non-rate-regulated enterprises. When this occurs, costs are deferred as assets in the balance sheet (regulatory assets) and recorded as expenses when those amounts are reflected in rates. Also, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for recovery of costs that are expected to be incurred in the future (regulatory liabilities).

The Company is subject to rate regulation by the Alabama Public Service Commission (the "Commission"), which has jurisdiction with respect to the rates of natural gas companies within Alabama's geography. The Company has stated that all regulatory assets and regulatory liabilities are recoverable or refundable through the regulatory process.

Accounting for the economics of rate regulation affects multiple financial statement line items, including property, plant, and equipment; regulatory assets and liabilities; operating revenues; and depreciation expense, and affects multiple disclosures in the Company's financial statements. There is a risk that the Commission will not approve full recovery of the costs of providing utility service or recovery of all amounts invested in the utility business and a reasonable return on that investment. As a result, we identified the impact of rate regulation as a critical audit matter due to the high degree of subjectivity involved in assessing the impact of current and future regulatory orders on events that have occurred as of September 30, 2022, and the judgments made by management to support their assertions about impacted account balances and disclosures. Management judgments included assessing the likelihood of (1) recovery in future rates of incurred costs or (2) refunds to customers or future reduction in rates. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the Commission, auditing these rate-impacted account balances and disclosures, and the related judgments, requires specialized knowledge of accounting for rate regulation due to the inherent complexities associated with the specialized rules related to accounting for the effects of cost-based regulation.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commission included the following, among others:

- We tested the effectiveness of management's controls over evaluating the likelihood of (1) the recovery in future rates of costs incurred as property, plant, and equipment and deferred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We tested the effectiveness of management's controls over the initial recognition of amounts as property, plant, and equipment; regulatory assets or liabilities; and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments, in the financial statements.
- We read relevant regulatory orders issued by the Commission for the Company in Alabama; regulatory statutes, interpretations, procedural memorandums, and filings made by interveners; and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commission's treatment of similar costs under similar circumstances.
- We obtained from management the regulatory orders that support the probability of recovery, refund, and/or future reduction in rates for regulatory assets and liabilities and assessed management's assertion that amounts are probable of recovery, refund, or a future reduction in rates.

/s/ Deloitte & Touche LLP

St. Louis, Missouri
November 16, 2022

We have served as the Company's auditor since 2014.

SPIRE INC.
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended September 30		
(In millions, except per share amounts)	**2022**	**2021**	**2020**
Operating Revenues	$ 2,198.5	$ 2,235.5	$ 1,855.4
Operating Expenses:			
Natural gas	923.9	946.3	696.1
Operation and maintenance	449.6	465.8	458.6
Depreciation and amortization	237.3	213.1	197.3
Taxes, other than income taxes	179.5	160.1	148.4
Impairments	—	—	148.6
Total Operating Expenses	1,790.3	1,785.3	1,649.0
Operating Income	408.2	450.2	206.4
Interest Expense, Net	119.8	106.6	105.5
Other (Expense) Income, Net	(8.7)	(3.4)	0.1
Income Before Income Taxes	279.7	340.2	101.0
Income Tax Expense	58.9	68.5	12.4
Net Income	220.8	271.7	88.6
Provision for preferred dividends	14.8	14.8	14.8
Income allocated to participating securities	0.3	0.4	0.1
Net Income Available to Common Shareholders	$ 205.7	$ 256.5	$ 73.7
Weighted Average Number of Common Shares Outstanding:			
Basic	52.0	51.6	51.2
Diluted	52.1	51.7	51.3
Basic Earnings Per Share of Common Stock	$ 3.96	$ 4.97	$ 1.44
Diluted Earnings Per Share of Common Stock	$ 3.95	$ 4.96	$ 1.44

See the accompanying Notes to Financial Statements.

SPIRE INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended September 30		
(In millions)	**2022**	**2021**	**2020**
Net Income	$ 220.8	$ 271.7	$ 88.6
Other Comprehensive Income (Loss), Before Tax:			
Cash flow hedging derivative instruments:			
Net hedging gain (loss) arising during the period	56.7	61.2	(8.9)
Amounts reclassified into net income	(1.2)	(1.3)	(3.2)
Net gain (loss) on cash flow hedging derivative instruments	55.5	59.9	(12.1)
Net gain (loss) on defined benefit pension and other postretirement plans	1.5	(1.3)	(0.5)
Net unrealized loss on available-for-sale debt securities	(0.4)	(0.2)	—
Other Comprehensive Income (Loss), Before Tax	56.6	58.4	(12.6)
Income Tax Expense (Benefit) Related to Items of Other Comprehensive Income (Loss)	13.0	13.6	(2.7)
Other Comprehensive Income (Loss), Net of Tax	43.6	44.8	(9.9)
Comprehensive Income	$ 264.4	$ 316.5	$ 78.7

See the accompanying Notes to Financial Statements.

SPIRE INC.
CONSOLIDATED BALANCE SHEETS

(In millions)	September 30 2022	2021
ASSETS		
Utility Plant	$ 7,664.9	$ 7,225.0
Less: Accumulated depreciation and amortization	2,294.5	2,169.3
Net Utility Plant	5,370.4	5,055.7
Non-utility Property (net of accumulated depreciation and amortization of $50.7 and $32.1 at September 30, 2022 and 2021, respectively)	491.4	471.1
Other Investments	87.8	83.1
Total Other Property and Investments	579.2	554.2
Current Assets:		
Cash and cash equivalents	6.5	4.3
Accounts receivable:		
Utility	210.8	338.4
Other	443.8	288.2
Allowance for credit losses	(31.9)	(30.3)
Delayed customer billings	21.3	9.2
Inventories:		
Natural gas	371.8	267.7
Propane gas	8.6	8.7
Materials and supplies	41.9	28.6
Regulatory assets	355.4	306.5
Prepayments	41.1	29.0
Other	122.7	66.2
Total Current Assets	1,592.0	1,316.5
Deferred Charges and Other Assets:		
Goodwill	1,171.6	1,171.6
Regulatory assets	1,112.4	993.5
Other	258.1	264.9
Total Deferred Charges and Other Assets	2,542.1	2,430.0
Total Assets	$ 10,083.7	$ 9,356.4

SPIRE INC.
CONSOLIDATED BALANCE SHEETS (Continued)

	September 30 2022	September 30 2021
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Preferred stock ($25.00 par value per share; 10.0 million depositary shares authorized, issued and outstanding at September 30, 2022 and 2021)	$ 242.0	$ 242.0
Common stock (par value $1.00 per share; 70.0 million shares authorized; 52.5 million issued and outstanding at September 30, 2022, and 51.7 million shares issued and outstanding at September 30, 2021)	52.5	51.7
Paid-in capital	1,571.3	1,517.9
Retained earnings	905.5	843.0
Accumulated other comprehensive income	47.2	3.6
Total Shareholders' Equity	2,818.5	2,658.2
Temporary equity	13.1	9.8
Long-term debt (less current portion)	2,958.5	2,939.1
Total Capitalization	5,790.1	5,607.1
Current Liabilities:		
Current portion of long-term debt	281.2	55.8
Notes payable	1,037.5	672.0
Accounts payable	617.4	409.9
Advance customer billings	18.7	32.1
Wages and compensation accrued	50.2	59.5
Customer deposits	28.2	28.9
Taxes accrued	90.1	78.8
Regulatory liabilities	3.7	34.6
Other	226.6	236.7
Total Current Liabilities	2,353.6	1,608.3
Deferred Credits and Other Liabilities:		
Deferred income taxes	675.1	612.3
Pension and postretirement benefit costs	163.0	235.9
Asset retirement obligations	520.9	519.6
Regulatory liabilities	418.2	620.9
Other	162.8	152.3
Total Deferred Credits and Other Liabilities	1,940.0	2,141.0
Commitments and Contingencies (Note 16)		
Total Capitalization and Liabilities	$ 10,083.7	$ 9,356.4

See the accompanying Notes to Financial Statements.

SPIRE INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(Dollars in millions, except per share amounts)	Common Stock Shares	Common Stock Par	Preferred Stock	Paid-in Capital	Retained Earnings	AOCI*	Total
Balance at September 30, 2019	50,973,515	$ 51.0	$ 242.0	$1,505.8	$ 775.5	$(31.3)	$2,543.0
Net income	—	—	—	—	88.6	—	88.6
Common stock issued	446,619	0.4	—	31.6	—	—	32.0
Dividend reinvestment plan	122,545	0.1	—	9.1	—	—	9.2
Stock-based compensation costs	—	—	—	6.0	—	—	6.0
Stock issued under stock-based compensation plans	110,463	0.1	—	(0.1)	—	—	—
Employees' tax withholding for stock-based compensation	(41,353)	—	—	(3.2)	—	—	(3.2)
Temporary equity adjustment to redemption value	—	—	—	—	3.4	—	3.4
Dividends declared:							
Common stock ($2.49 per share)	—	—	—	—	(128.4)	—	(128.4)
Preferred stock ($1.84375 per depositary share)	—	—	—	—	(18.4)	—	(18.4)
Other comprehensive loss, net of tax	—	—	—	—	—	(9.9)	(9.9)
Balance at September 30, 2020	51,611,789	$ 51.6	$ 242.0	$1,549.2	$ 720.7	$(41.2)	$2,522.3
Net income	—	—	—	—	271.7	—	271.7
Dividend reinvestment plan	24,565	—	—	1.6	—	—	1.6
Stock-based compensation costs	—	—	—	9.1	—	—	9.1
Stock issued under stock-based compensation plans	65,316	0.1	—	(0.1)	—	—	—
Employees' tax withholding for stock-based compensation	(16,787)	—	—	(1.1)	—	—	(1.1)
Equity units issued	—	—	—	(40.8)	—	—	(40.8)
Temporary equity adjustment to redemption value	—	—	—	—	1.3	—	1.3
Dividends declared:							
Common stock ($2.60 per share)	—	—	—	—	(135.9)	—	(135.9)
Preferred stock ($1.475 per depositary share)	—	—	—	—	(14.8)	—	(14.8)
Other comprehensive income, net of tax	—	—	—	—	—	44.8	44.8
Balance at September 30, 2021	51,684,883	$ 51.7	$ 242.0	$1,517.9	$ 843.0	$ 3.6	$2,658.2
Net income	—	—	—	—	220.8	—	220.8
Common stock issued	719,625	0.7	—	49.6	—	—	50.3
Dividend reinvestment plan	24,154	—	—	1.6	—	—	1.6
Stock-based compensation costs	—	—	—	4.1	—	—	4.1
Stock issued under stock-based compensation plans	93,936	0.1	—	(0.1)	—	—	—
Employees' tax withholding for stock-based compensation	(28,055)	—	—	(1.8)	—	—	(1.8)
Dividends declared:							
Common stock ($2.74 per share)	—	—	—	—	(143.5)	—	(143.5)
Preferred stock ($1.475 per depositary share)	—	—	—	—	(14.8)	—	(14.8)
Other comprehensive income, net of tax	—	—	—	—	—	43.6	43.6
Balance at September 30, 2022	52,494,543	$ 52.5	$ 242.0	$1,571.3	$ 905.5	$ 47.2	$2,818.5

* Accumulated other comprehensive income (loss)

See the accompanying Notes to Financial Statements.

SPIRE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended September 30		
(In millions)	**2022**	**2021**	**2020**
Operating Activities:			
Net Income	$ 220.8	$ 271.7	$ 88.6
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	237.3	213.1	197.3
Impairments	—	—	148.6
Deferred income taxes and investment tax credits	57.9	67.0	9.0
Changes in assets and liabilities:			
Accounts receivable	(26.5)	(343.0)	36.2
Inventories	(117.2)	(111.0)	2.6
Regulatory assets and liabilities	(409.0)	76.6	0.6
Accounts payable	190.7	177.7	(43.1)
Delayed/advance customer billings, net	(25.5)	(12.4)	7.0
Taxes accrued	11.2	8.9	2.9
Other assets and liabilities	(93.5)	(116.1)	12.0
Other	8.8	17.3	8.2
Net cash provided by operating activities	55.0	249.8	469.9
Investing Activities:			
Capital expenditures	(552.2)	(624.8)	(638.4)
Other	5.5	2.8	6.8
Net cash used in investing activities	(546.7)	(622.0)	(631.6)
Financing Activities:			
Issuance of long-term debt	300.0	629.1	510.0
Repayment of long-term debt	(55.8)	(115.4)	(147.0)
Issuance (repayment) of short-term debt, net	365.5	24.0	(95.2)
Issuance of common stock	51.9	1.0	41.1
Dividends paid on common stock	(141.9)	(133.2)	(128.0)
Dividends paid on preferred stock	(14.8)	(14.8)	(14.8)
Other	(4.0)	(11.3)	(6.1)
Net cash provided by financing activities	500.9	379.4	160.0
Net Increase (Decrease) in Cash, Cash Equivalents, and Restricted Cash	9.2	7.2	(1.7)
Cash, Cash Equivalents, and Restricted Cash at Beginning of Year	11.3	4.1	5.8
Cash, Cash Equivalents, and Restricted Cash at End of Year	$ 20.5	$ 11.3	$ 4.1
Supplemental disclosure of cash paid for:			
Interest, net of amounts capitalized	$ (119.9)	$ (98.7)	$ (100.0)
Income taxes	(1.8)	(1.5)	(2.9)

See the accompanying Notes to Financial Statements.

SPIRE MISSOURI INC.
STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended September 30		
(In millions)	**2022**	**2021**	**2020**
Operating Revenues	$ 1,321.0	$ 1,516.6	$ 1,193.6
Operating Expenses:			
Natural gas	587.0	786.8	515.8
Operation and maintenance	255.7	261.1	251.0
Depreciation and amortization	145.3	129.2	118.0
Taxes, other than income taxes	129.0	110.9	103.2
Total Operating Expenses	1,117.0	1,288.0	988.0
Operating Income	204.0	228.6	205.6
Interest Expense, Net	60.9	50.3	49.4
Other Expense, Net	(6.9)	(8.9)	(8.7)
Income Before Income Taxes	136.2	169.4	147.5
Income Tax Expense	21.3	25.3	17.3
Net Income	114.9	144.1	130.2
Other Comprehensive Income (Loss), Net of Tax	1.5	(1.3)	(0.5)
Comprehensive Income	$ 116.4	$ 142.8	$ 129.7

See the accompanying Notes to Financial Statements.

SPIRE MISSOURI INC.
BALANCE SHEETS

	September 30	
(In millions)	**2022**	**2021**
ASSETS		
Utility Plant	$ 4,550.4	$ 4,266.6
Less: Accumulated depreciation and amortization	982.1	905.1
Net Utility Plant	3,568.3	3,361.5
Other Property and Investments	58.9	60.2
Current Assets:		
Accounts receivable:		
Utility	131.5	279.0
Associated companies	3.7	4.7
Other	44.5	57.5
Allowance for credit losses	(24.9)	(22.6)
Delayed customer billings	16.1	2.4
Inventories:		
Natural gas	215.3	176.7
Propane gas	8.6	8.7
Materials and supplies	22.0	15.0
Regulatory assets	288.1	276.3
Prepayments	23.3	19.7
Other	—	0.1
Total Current Assets	728.2	817.5
Deferred Charges and Other Assets:		
Goodwill	210.2	210.2
Regulatory assets	547.6	483.1
Other	105.0	125.6
Total Deferred Charges and Other Assets	862.8	818.9
Total Assets	$ 5,218.2	$ 5,058.1

SPIRE MISSOURI INC.
BALANCE SHEETS (continued)

	September 30	
	2022	**2021**
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stock (par value $1.00 per share; 50.0 million shares authorized; 25,325 issued and outstanding at September 30, 2022 and 24,577 issued and outstanding at 2021)	$ 0.1	$ 0.1
Paid-in capital	816.1	765.0
Retained earnings	931.9	817.0
Accumulated other comprehensive loss	(2.7)	(4.2)
Total Shareholder's Equity	1,745.4	1,577.9
Long-term debt (less current portion)	1,387.7	1,338.4
Total Capitalization	3,133.1	2,916.3
Current Liabilities:		
Current portion of long-term debt	250.0	—
Notes payable	—	250.0
Notes payable – associated companies	445.3	240.9
Accounts payable	119.0	89.7
Accounts payable – associated companies	13.3	10.2
Advance customer billings	7.0	19.7
Wages and compensation accrued	33.8	40.3
Customer deposits	6.5	8.0
Taxes accrued	50.4	41.2
Regulatory liabilities	—	17.1
Other	45.6	47.4
Total Current Liabilities	970.9	764.5
Deferred Credits and Other Liabilities:		
Deferred income taxes	500.1	480.0
Pension and postretirement benefit costs	115.5	159.5
Asset retirement obligations	110.6	143.4
Regulatory liabilities	331.8	538.8
Other	56.2	55.6
Total Deferred Credits and Other Liabilities	1,114.2	1,377.3
Commitments and Contingencies (Note 16)		
Total Capitalization and Liabilities	$ 5,218.2	$ 5,058.1

See the accompanying Notes to Financial Statements.

SPIRE MISSOURI INC.
STATEMENTS OF SHAREHOLDER'S EQUITY

(Dollars in millions)	Common Stock Shares	Common Stock Par	Paid-in Capital	Retained Earnings	AOCI*	Total
Balance at September 30, 2019	24,577	$ 0.1	$ 765.0	$ 576.6	$ (2.4)	$ 1,339.3
Net income	—	—	—	130.2	—	130.2
Dividends declared	—	—	—	(33.9)	—	(33.9)
Other comprehensive loss, net of tax	—	—	—	—	(0.5)	(0.5)
Balance at September 30, 2020	24,577	0.1	765.0	672.9	(2.9)	1,435.1
Net income	—	—	—	144.1	—	144.1
Other comprehensive loss, net of tax	—	—	—	—	(1.3)	(1.3)
Balance at September 30, 2021	24,577	0.1	765.0	817.0	(4.2)	1,577.9
Net income	—	—	—	114.9	—	114.9
Common stock issued to Spire Inc.	748	—	51.1	—	—	51.1
Other comprehensive income, net of tax	—	—	—	—	1.5	1.5
Balance at September 30, 2022	25,325	$ 0.1	$ 816.1	$ 931.9	$ (2.7)	$ 1,745.4

* Accumulated other comprehensive income (loss)

See the accompanying Notes to Financial Statements.

SPIRE MISSOURI INC.
STATEMENTS OF CASH FLOWS

(In millions)	2022	2021	2020
	Years Ended September 30		
Operating Activities:			
Net Income	$ 114.9	$ 144.1	$ 130.2
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	145.3	129.2	118.0
Deferred income taxes and investment tax credits	21.3	25.3	17.1
Changes in assets and liabilities:			
Accounts receivable	163.8	(207.4)	(3.7)
Inventories	(45.4)	(79.0)	2.7
Regulatory assets and liabilities	(314.3)	35.9	27.3
Accounts payable	25.3	23.1	2.3
Delayed/advance customer billings, net	(26.4)	(13.0)	13.7
Taxes accrued	9.3	2.1	2.7
Other assets and liabilities	(48.0)	(115.0)	(6.1)
Other	1.4	0.7	0.6
Net cash provided by (used in) operating activities	47.2	(54.0)	304.8
Investing Activities:			
Capital expenditures	(354.1)	(382.6)	(356.0)
Other	3.6	1.3	1.3
Net cash used in investing activities	(350.5)	(381.3)	(354.7)
Financing Activities:			
Issuance of long-term debt	300.0	304.1	275.0
Repayment of long-term debt	—	(55.0)	(107.0)
(Repayment) issuance of short-term debt, net	(250.0)	250.0	—
Borrowings from (repayments to) Spire, net	204.4	(60.3)	(85.2)
Issuance of common stock	51.1	—	—
Dividends paid	—	—	(33.9)
Other	(2.2)	(3.5)	(1.6)
Net cash provided by financing activities	303.3	435.3	47.3
Net Decrease in Cash and Cash Equivalents	—	—	(2.6)
Cash and Cash Equivalents at Beginning of Year	—	—	2.6
Cash and Cash Equivalents at End of Year	$ —	$ —	$ —
Supplemental disclosure of cash paid for:			
Interest, net of amounts capitalized	$ (58.9)	$ (45.9)	$ (46.0)
Income taxes	—	—	—

See the accompanying Notes to Financial Statements.

SPIRE ALABAMA INC.
STATEMENTS OF INCOME

(In millions)	Years Ended September 30 2022	2021	2020
Operating Revenues	$ 509.1	$ 494.0	$ 455.0
Operating Expenses:			
Natural gas	161.5	145.3	118.9
Operation and maintenance	130.1	132.5	139.1
Depreciation and amortization	66.8	62.1	59.3
Taxes, other than income taxes	38.1	37.1	34.8
Total Operating Expenses	396.5	377.0	352.1
Operating Income	112.6	117.0	102.9
Interest Expense, Net	21.3	20.2	20.6
Other Income, Net	0.4	2.0	5.4
Income Before Income Taxes	91.7	98.8	87.7
Income Tax Expense	23.2	25.0	22.0
Net Income	$ 68.5	$ 73.8	$ 65.7

See the accompanying Notes to Financial Statements.

SPIRE ALABAMA INC.
BALANCE SHEETS

	September 30	
(In millions)	**2022**	**2021**
ASSETS		
Utility Plant	$ 2,732.6	$ 2,586.5
Less: Accumulated depreciation and amortization	1,184.1	1,124.8
Net Utility Plant	1,548.5	1,461.7
Current Assets:		
Cash and cash equivalents	2.4	—
Accounts receivable:		
Utility	69.9	49.8
Associated companies	1.3	0.6
Other	6.5	6.4
Allowance for credit losses	(6.3)	(6.6)
Delayed customer billings	4.8	6.7
Inventories:		
Natural gas	72.5	35.5
Materials and supplies	16.3	10.8
Regulatory assets	56.9	18.8
Prepayments	5.8	5.4
Total Current Assets	230.1	127.4
Deferred Charges and Other Assets:		
Regulatory assets	538.2	483.3
Deferred income tax	11.0	34.2
Other	81.3	63.9
Total Deferred Charges and Other Assets	630.5	581.4
Total Assets	$ 2,409.1	$ 2,170.5

SPIRE ALABAMA INC.
BALANCE SHEETS (continued)

	September 30	
	2022	2021
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stock and paid-in capital (par value $0.01 per share; 3,000,000 shares authorized; 1,972,052 issued and outstanding at September 30, 2022 and 2021)	$ 316.9	$ 328.9
Retained earnings	589.1	552.6
Total Shareholder's Equity	906.0	881.5
Long-term debt (less current portion)	571.5	571.2
Total Capitalization	1,477.5	1,452.7
Current Liabilities:		
Current portion of long-term debt	—	50.0
Notes payable – associated companies	260.9	49.0
Accounts payable	85.6	52.3
Accounts payable – associated companies	4.4	6.0
Advance customer billings	9.9	11.2
Wages and compensation accrued	7.6	9.3
Customer deposits	19.0	18.4
Taxes accrued	31.3	30.4
Regulatory liabilities	—	13.4
Other	22.4	17.3
Total Current Liabilities	441.1	257.3
Deferred Credits and Other Liabilities:		
Pension and postretirement benefit costs	40.5	66.7
Asset retirement obligations	398.7	362.8
Regulatory liabilities	23.0	23.4
Other	28.3	7.6
Total Deferred Credits and Other Liabilities	490.5	460.5
Commitments and Contingencies (Note 16)		
Total Capitalization and Liabilities	$ 2,409.1	$ 2,170.5

See the accompanying Notes to Financial Statements.

SPIRE ALABAMA INC.
STATEMENTS OF SHAREHOLDER'S EQUITY

	Common Stock		Paid-in	Retained	
(Dollars in millions)	**Shares**	**Par**	**Capital**	**Earnings**	**Total**
Balance at September 30, 2019	1,972,052	$ —	$ 370.9	$ 459.1	$ 830.0
Net income	—	—	—	65.7	65.7
Dividends declared	—	—	—	(24.0)	(24.0)
Return of capital to Spire	—	—	(20.0)	—	(20.0)
Balance at September 30, 2020	1,972,052	—	350.9	500.8	851.7
Net income	—	—	—	73.8	73.8
Dividends declared	—	—	—	(22.0)	(22.0)
Return of capital to Spire	—	—	(22.0)	—	(22.0)
Balance at September 30, 2021	1,972,052	—	328.9	552.6	881.5
Net income	—	—	—	68.5	68.5
Dividends declared	—	—	—	(32.0)	(32.0)
Return of capital to Spire	—	—	(12.0)	—	(12.0)
Balance at September 30, 2022	1,972,052	$ —	$ 316.9	$ 589.1	$ 906.0

See the accompanying Notes to Financial Statements.

SPIRE ALABAMA INC.
STATEMENTS OF CASH FLOWS

(In millions)	Years Ended September 30 2022	2021	2020
Operating Activities:			
Net Income	$ 68.5	$ 73.8	$ 65.7
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	66.8	62.1	59.3
Deferred income taxes	23.2	25.0	22.0
Changes in assets and liabilities:			
Accounts receivable	(21.2)	(17.8)	7.3
Inventories	(42.5)	(15.4)	11.9
Regulatory assets and liabilities	(101.7)	29.2	(23.5)
Accounts payable	26.3	14.0	(15.1)
Delayed/advance customer billings	0.5	0.5	(6.6)
Taxes accrued	0.8	2.5	0.6
Other assets and liabilities	(3.7)	(37.8)	18.9
Other	0.2	0.3	0.2
Net cash provided by operating activities	17.2	136.4	140.7
Investing Activities:			
Capital expenditures	(141.5)	(169.8)	(150.4)
Other	0.8	0.7	1.6
Net cash used in investing activities	(140.7)	(169.1)	(148.8)
Financing Activities:			
Issuance of long-term debt	—	150.0	100.0
Repayment of long-term debt	(50.0)	—	(40.0)
Borrowings from (repayments to) Spire, net	211.9	(72.4)	(7.4)
Return of capital to Spire	(12.0)	(22.0)	(20.0)
Dividends paid	(24.0)	(22.0)	(24.0)
Other	—	(0.9)	(0.5)
Net cash provided by financing activities	125.9	32.7	8.1
Net Increase in Cash and Cash Equivalents	2.4	—	—
Cash and Cash Equivalents at Beginning of Year	—	—	—
Cash and Cash Equivalents at End of Year	$ 2.4	$ —	$ —
Supplemental disclosure of cash paid for:			
Interest, net of amounts capitalized	$ (21.0)	$ (17.9)	$ (19.0)
Income taxes	—	—	—

See the accompanying Notes to Financial Statements.

SPIRE INC., SPIRE MISSOURI INC., AND SPIRE ALABAMA INC.
NOTES TO FINANCIAL STATEMENTS
(Dollars in millions, except per share, per unit and per gallon amounts)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION – These notes are an integral part of the accompanying audited financial statements of Spire Inc. ("Spire" or the "Company") presented on a consolidated basis, Spire Missouri Inc. ("Spire Missouri") and Spire Alabama Inc. ("Spire Alabama"). Spire Missouri, Spire Alabama and Spire EnergySouth Inc. ("Spire EnergySouth") are wholly owned subsidiaries of Spire. Spire Missouri, Spire Alabama and the subsidiaries of Spire EnergySouth (Spire Gulf Inc. and Spire Mississippi Inc.) are collectively referred to as the "Utilities." Unless otherwise indicated, references to years herein are references to the fiscal years ending September 30 for the Company and its subsidiaries.

The accompanying audited financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). The consolidated financial position, results of operations and cash flows of Spire include the accounts of the Company and all its subsidiaries. Transactions and balances between consolidated entities have been eliminated from the consolidated financial statements of Spire. In compliance with GAAP, transactions between Spire Missouri and Spire Alabama and their affiliates, as well as intercompany balances on their balance sheets, have not been eliminated from their separate financial statements.

NATURE OF OPERATIONS – Spire has two reportable segments: Gas Utility and Gas Marketing. The Gas Utility segment consists of the regulated natural gas distribution operations of the Company and is the core business segment of Spire in terms of revenue and earnings. The Gas Utility segment is comprised of the operations of: Spire Missouri, serving St. Louis, Kansas City, and other areas in Missouri; Spire Alabama, serving central and northern Alabama; and the subsidiaries of Spire EnergySouth, serving the Mobile, Alabama area and south-central Mississippi. The Gas Marketing segment includes Spire's primary gas-related business, Spire Marketing Inc. ("Spire Marketing"), which provides non-regulated natural gas services throughout the United States (U.S.). The activities of the Company's other subsidiaries are reported as Other and are described in Note 14, Information by Operating Segment. Spire Missouri and Spire Alabama each have a single reportable segment.

USE OF ESTIMATES – The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

SYSTEM OF ACCOUNTS – The accounts of the Utilities are maintained in accordance with the Uniform System of Accounts prescribed by the applicable state public service commissions, which systems substantially conform to that prescribed by the Federal Energy Regulatory Commission (FERC).

REGULATED OPERATIONS – The Utilities account for their regulated operations in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 980, *Regulated Operations*. This topic sets forth the application of GAAP for those companies whose rates are established by or are subject to approval by an independent third-party regulator. The provisions of this accounting guidance require, among other things, that financial statements of a regulated enterprise reflect the actions of regulators, where appropriate. These actions may result in the recognition of revenues and expenses in time periods that are different than non-regulated enterprises. When this occurs, costs are deferred as assets in the balance sheet (regulatory assets) and recorded as expenses when those amounts are reflected in rates. In addition, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for recovery of costs that are expected to be incurred in the future (regulatory liabilities). Management believes that the current regulatory environment supports the continued use of these regulatory accounting principles and that all regulatory assets and regulatory liabilities are recoverable or refundable through the regulatory process. See additional discussion on regulated operations in Note 15, Regulatory Matters.

PROPERTY, PLANT, AND EQUIPMENT –

Utility Plant – Utility plant is stated at original cost. The cost of additions to utility plant includes contracted work, direct labor and materials, allocable overheads and an allowance for funds used during construction. The costs of units of property retired, replaced or renewed are removed from utility plant and are charged to accumulated depreciation. Maintenance and repairs of property and replacement and renewal of items determined to be less than units of property are charged to maintenance expenses.

Utility plant is depreciated using the composite method on a straight-line basis over the estimated service lives of the various classes of property at rates approved by the applicable regulatory commission. For Spire Missouri and for Spire Alabama, the annual depreciation and amortization expense in fiscal years 2022, 2021 and 2020 averaged approximately 3% of the original cost of depreciable and amortizable property.

Non-utility Property – Non-utility property is recorded at the original cost of acquisition or construction, which includes material, labor, contractor services and, for FERC-regulated projects, an allowance for funds used during construction. Repairs, replacements and renewals of items of property determined to be less than a unit of property or that do not increase the property's life or functionality are charged to maintenance expense. Upon retirement or sale of non-utility property, the original cost and related accumulated depreciation are removed from the accounts and any gain or loss is included in the income statements. Costs related to software developed or obtained for internal use are capitalized and amortized on a straight-line basis over the estimated useful life of the related software. If software is retired prior to being fully amortized, the difference is recorded as a loss in the income statements.

Accrued Capital Expenditures – Accrued capital expenditures, shown in the following table, are excluded from capital expenditures in the statements of cash flows until paid.

September 30	2022	2021	2020
Spire	$ 77.8	$ 59.5	$ 67.6
Spire Missouri	45.6	37.1	34.3
Spire Alabama	19.2	13.6	17.0

ASSET RETIREMENT OBLIGATIONS – Spire, Spire Missouri and Spire Alabama record legal obligations associated with the retirement of long-lived assets in the period in which the obligations are incurred, if sufficient information exists to reasonably estimate the fair value of the obligations. Obligations are recorded as both a cost of the related long-lived asset and as a corresponding liability. Subsequently, the asset retirement costs are depreciated over the life of the asset and the asset retirement obligations are accreted to the expected settlement amounts. The Company, Spire Missouri and Spire Alabama record asset retirement obligations associated with certain safety requirements to purge and seal gas distribution mains upon retirement, the plugging and abandonment of storage wells and other storage facilities, specific service line obligations, and certain removal and disposal obligations related to components of Spire Missouri's, Spire Alabama's and Spire Gulf's distribution systems and general plant. Asset retirement obligations recorded by Spire's other subsidiaries are not material. As authorized by the Missouri Public Service Commission (MoPSC) and the Alabama Public Service Commission (APSC), Spire Missouri, Spire Alabama and Spire Gulf accrue future asset removal costs associated with their property, plant and equipment even if a legal obligation does not exist. Such accruals are provided for through depreciation expense and are recorded with corresponding credits to regulatory liabilities or regulatory assets. When those utilities retire depreciable utility plant and equipment, they charge the associated original costs to accumulated depreciation and amortization, and any related removal costs incurred are charged to regulatory liabilities or regulatory assets. The difference between removal costs recognized in depreciation rates and the accretion expense and depreciation expense recognized for financial reporting purposes is a timing difference between recovery of these costs in rates and their recognition for financial reporting purposes. Accordingly, these differences are deferred as regulatory liabilities or regulatory assets. In the rate setting process, the regulatory liabilities or regulatory assets are excluded from the rate base upon which those utilities have the opportunity to earn their allowed rates of return.

The following table presents a reconciliation of the beginning and ending balances of asset retirement obligations at September 30, as reported in the balance sheets.

	Spire		Spire Missouri		Spire Alabama	
	2022	2021	2022	2021	2022	2021
Asset retirement obligations, beginning of year	$ 519.6	$ 540.1	$ 143.4	$ 153.4	$ 362.8	$ 374.3
Liabilities incurred during the period	3.2	11.1	1.2	1.4	0.5	7.4
Liabilities settled during the period	(9.2)	(21.9)	(4.1)	(9.7)	(2.0)	(10.7)
Accretion	21.1	21.8	5.9	6.2	14.7	15.0
Revisions in estimated cash flows	(13.8)	(31.5)	(35.8)	(7.9)	22.7	(23.2)
Asset retirement obligations, end of year	$ 520.9	$ 519.6	$ 110.6	$ 143.4	$ 398.7	$ 362.8

NATURAL GAS AND PROPANE GAS – For Spire Missouri's eastern region, inventory of natural gas in storage is priced on a last in, first out (LIFO) basis and inventory of propane gas in storage is priced on a first in, first out (FIFO) basis. For the rest of the Gas Utility segment, inventory of natural gas in storage is priced on the weighted average cost basis. The replacement cost of Spire Missouri's natural gas for current use in eastern Missouri at September 30, 2022 was more than the LIFO cost by $37.3. The replacement cost of Spire Missouri's natural gas for current use in eastern Missouri at September 30, 2021 was less than the LIFO cost by $14.0. The carrying value of the Utilities' inventory is never adjusted to a lower net realizable value or market value because, pursuant to Purchased Gas Adjustment (PGA) clauses or a Gas Supply Adjustment (GSA) rider, actual gas costs are recovered in customer rates. Natural gas and propane gas storage inventory in Spire's other operating segments is recorded at the lower of average cost or net realizable value.

BUSINESS COMBINATIONS AND GOODWILL – Spire's acquisitions were accounted for using business combination accounting. Under this method, the purchase price paid by the acquirer is allocated to the assets acquired and liabilities assumed as of the acquisition date based on their fair value. Goodwill is measured as the excess of the acquisition-date fair value of the consideration transferred over the amount of acquisition-date identifiable assets acquired net of assumed liabilities. At September 30, 2022, goodwill included in Spire's Gas Utility and Gas Marketing segments was $210.2 and zero, respectively, with the remainder held at the corporate level. Goodwill amounts have not changed since fiscal 2017, and there are no accumulated impairment losses. Spire and Spire Missouri evaluate goodwill for impairment as of July 1 of each year, or more frequently if events and circumstances indicate that goodwill might be impaired. At each test date, the assessments concluded that goodwill was not impaired. The Company updated the assessments as of September 30, 2022, determining that it remained more likely than not that the fair value of each reporting unit exceeded its carrying value.

IMPAIRMENT OF LONG-LIVED ASSETS – Long-lived assets classified as held and used are evaluated for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Whether impairment has occurred is determined by comparing the estimated undiscounted cash flows attributable to the assets with the carrying value of the assets. If the carrying value exceeds the undiscounted cash flows, the Company recognizes an impairment charge equal to the amount of the carrying value that exceeds the estimated fair value of the assets. In the period in which the Company determines an asset meets held-for-sale criteria, an impairment charge is recorded to the extent the book value exceeds its fair value less cost to sell.

On July 1, 2020, Spire's Board of Directors, based upon the recommendation of senior management, revised the development plan for Spire Storage, resulting in an impairment charge of $140.8 related to Spire Storage assets (non-utility property on the balance sheet) in the quarter ended June 30, 2020. The revision was driven by the realization that a longer time horizon will be required for optimization and positioning of the storage facility to serve energy markets in the western United States. Among other factors, evaluations of the continuing evolution of market dynamics in the region led management to update models of various development alternatives. Separately in the quarter ended June 30, 2020, Spire recorded impairment charges totaling $7.8 related to two commercial compressed natural gas fueling stations (also non-utility property) as a result of revised projections reflecting lower diesel prices and slower conversions of Class 8 vehicles. The fair values used in measuring the impairment charges were determined with an expected present value technique using a discounted cash flow method under an income approach. In the quarter ended September 30, 2021, Spire sold one of the fueling stations and recorded a gain of $1.3.

DERIVATIVES – In the course of their business, certain subsidiaries of Spire enter into commitments associated with the purchase or sale of natural gas. Certain of their derivative natural gas contracts are designated as normal purchases or normal sales and, as such, are excluded from the scope of FASB ASC Topic 815, *Derivatives and Hedging*. Those contracts are accounted for as executory contracts and recorded on an accrual basis. Revenues and expenses from such contracts are recorded gross. Contracts not designated as normal purchases or normal sales are recorded as derivatives with changes in fair value recognized in earnings in the periods prior to physical delivery. Certain of Spire Marketing's wholesale purchase and sale transactions are classified as trading activities for financial reporting purposes, with income and expenses presented on a net basis in natural gas expenses in the Consolidated Statements of Income. Spire also enters into cash flow hedges through execution of interest rate swap contracts to protect itself against adverse movements in interest rates. Refer to Note 10, Derivative Instruments and Hedging Activities, for more information about derivatives.

INCOME TAXES – Spire and its subsidiaries account for income taxes under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amount of existing assets and liabilities and the respective tax basis and for tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be realized or settled. The effects on deferred tax assets and liabilities of a change in enacted tax rates is recognized in income or loss for non-regulated operations, and in a regulatory asset or regulatory liability for regulated operations. A valuation allowance is established when it is more likely than not that some portion or all of the deferred tax assets will not be realized.

The Company accounts for uncertain tax positions in accordance with authoritative guidance. The authoritative guidance addresses the determination of whether tax benefits claimed, or expected to be claimed, on a tax return should be recorded in the financial statements. Spire may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the position will be sustained upon examination by the taxing authority, based on the technical merits of the position. Tax-related interest and penalties, if any, are classified as a liability on the balance sheets. For additional information on the accounting for income taxes, refer to Note 12, Income Taxes.

CASH, CASH EQUIVALENTS, AND RESTRICTED CASH – All highly liquid debt instruments purchased with original maturities of three months or less are considered to be cash equivalents. Such instruments are carried at cost, which approximates market value. Outstanding checks on the Company's and Utilities' bank accounts in excess of funds on deposit create book overdrafts (which are funded at the time checks are presented for payment) and are classified as Other in the Current Liabilities section of the balance sheets. Changes in book overdrafts are reflected as Operating Activities in the statements of cash flows. In Spire's statements of cash flows, total Cash, Cash Equivalents, and Restricted Cash included $14.0 and $7.0 of restricted cash reported in "Other Investments" on the Company's balance sheet as of September 30, 2022 and 2021, respectively (in addition to amounts shown as "Cash and cash equivalents"). This restricted cash has been segregated and invested in debt securities in a trust account based on collateral requirements for reinsurance at Spire's risk management company.

NATURAL GAS RECEIVABLE – Spire Marketing enters into natural gas transactions with natural gas pipeline and storage companies known as park and loan arrangements. Under the terms of the arrangements, Spire Marketing purchases natural gas from a third party and delivers that natural gas to the pipeline or storage company for the right to receive the same quantity of natural gas from that company at the same location in a future period. These arrangements are accounted for as non-monetary transactions under GAAP and are recorded at the carrying amount. As such, natural gas receivables are reflected in "Other" current assets on the Consolidated Balance Sheets at cost, which includes related fees associated with the transactions. In the period that the natural gas is returned to Spire Marketing, concurrent with the sale of the natural gas to a third party, the related natural gas receivable is expensed in the Consolidated Statements of Income. In conjunction with these transactions, Spire Marketing usually enters into New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE) natural gas futures, options, and swap contracts or fixed price sales agreements to protect against market changes in future sales prices.

EARNINGS PER COMMON SHARE – GAAP requires dual presentation of basic and diluted earnings per share (EPS). EPS is computed using the two-class method, which is an earnings allocation method for computing EPS that treats a participating security as having rights to earnings that would otherwise have been available to common shareholders. Certain of the Company's stock-based compensation awards pay non-forfeitable dividends to the participants during the vesting period and, as such, are deemed participating securities. Basic EPS is computed by dividing net income available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS is computed by dividing net income available to common shareholders by the weighted average number of common shares outstanding that are increased for additional shares that would be outstanding if potentially dilutive non-participating securities were converted to common shares, pursuant to the treasury stock method. Shares attributable to equity units, non-participating stock options and time-vested restricted stock/units are excluded from the calculation of diluted earnings per share if the effect would be antidilutive. Shares attributable to non-participating performance-contingent restricted stock awards are only included in the calculation of diluted earnings per share to the extent the underlying performance and/or market conditions are satisfied (a) prior to the end of the reporting period or (b) would be satisfied if the end of the reporting period were the end of the related contingency period and the result would be dilutive. The Company's EPS computations are presented in Note 4, Earnings Per Common Share.

TRANSACTIONS WITH AFFILIATES – Transactions between affiliates of the Company have been eliminated from the consolidated financial statements of Spire. Spire Missouri and Spire Alabama borrowed funds from the Company and incurred related interest, as reflected in their separate financial statements, and they participated in normal intercompany shared services transactions. In addition, Spire Missouri's and Spire Alabama's other transactions with affiliates included:

	Spire Missouri			Spire Alabama		
	2022	2021	2020	2022	2021	2020
Natural gas purchases from Spire Marketing	$ 86.3	$ 92.5	$ 56.9	$ 3.2	$ 10.4	$ 6.3
Natural gas sales to Spire Marketing	—	1.1	0.1	0.5	0.1	0.3
Transportation services from Spire STL Pipeline LLC	32.0	32.0	27.9	—	—	—
Transportation services from Spire NGL Inc.	—	0.5	1.0	—	—	—

ACCOUNTS RECEIVABLE AND ALLOWANCE FOR CREDIT LOSSES – Trade accounts receivable are recorded at the amounts due from customers, including unbilled amounts. Accounts receivable are written off when they are deemed to be uncollectible. An allowance for expected credit losses is estimated and updated based on relevant data and trends such as accounts receivable aging, historical write-off experience, current write-off trends, economic conditions, and the impact of weather and availability of customer payment assistance on collection trends. For the Utilities, net write-offs as a percentage of revenue has historically been the best predictor of base net write-off experience over time. Management judgment is applied in the development of the allowance due to the complexity of variables and subjective nature of certain relevant factors. The estimates for expected credit losses were increased as a result of considerations related to the outbreak of COVID-19 in 2020, including trends from previous economic downturns, the effects of moratoriums on gas service cutoffs, and the effects of slower-than-normal disconnection activity in general, offset by the amount subject to specific recovery under Missouri's deferral order (see Note 15, Regulatory Matters). The accounts receivable of Spire's non-utility businesses are evaluated separately from those of the Utilities. The allowance for credit losses for those other businesses is based on a continuous evaluation of the individual counterparty risk and is not significant for the periods presented. Activity in the allowance for credit losses is shown in the following table.

	Spire			Spire Missouri			Spire Alabama		
	2022	2021	2020	2022	2021	2020	2022	2021	2020
Allowance at beginning of year	$ 30.3	$ 24.9	$ 23.0	$ 22.6	$ 18.1	$ 14.9	$ 6.6	$ 5.5	$ 6.3
Provision for expected credit losses	11.6	14.7	14.0	11.2	11.1	12.7	0.3	3.1	0.9
Write-offs, net of recoveries	(10.0)	(9.3)	(12.1)	(8.9)	(6.6)	(9.5)	(0.6)	(2.0)	(1.7)
Allowance at end of year	$ 31.9	$ 30.3	$ 24.9	$ 24.9	$ 22.6	$ 18.1	$ 6.3	$ 6.6	$ 5.5

FINANCE RECEIVABLES – Spire Alabama finances third party contractor sales of merchandise including gas furnaces and appliances. At September 30, 2022 and 2021, Spire Alabama's finance receivable totaled approximately $7.1 and $7.8, respectively. Financing is available only to qualified customers who meet creditworthiness thresholds for customer payment history and external agency credit reports. Spire Alabama relies upon ongoing payments as the primary indicator of credit quality during the term of each contract. The allowance for credit losses is recognized using an estimate of write-off percentages based on historical experience. Delinquent accounts are evaluated on a case-by-case basis and, absent evidence of debt repayment, after 90 days are due in full and assigned to a third-party collection agency. The remaining finance receivable is written off approximately 12 months after being assigned to the third-party collection agency. Spire Alabama had finance receivables past due 90 days or more of $0.3 at September 30, 2022 and 2021.

GROUP MEDICAL AND WORKERS' COMPENSATION RESERVES – The Company self-insures its group medical and workers' compensation costs and carries stop-loss coverage in relation to medical claims and workers' compensation claims. Reserves for amounts incurred but not reported are established based on historical cost levels and lags between occurrences and reporting.

FAIR VALUE MEASUREMENTS – Certain assets and liabilities are recognized or disclosed at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). GAAP establishes a fair value hierarchy that prioritizes the inputs used to measure fair value.

The levels of the hierarchy are described below:

- Level 1 – Unadjusted quoted prices in active markets for identical assets or liabilities.

- Level 2 – Pricing inputs other than quoted prices included within Level 1, which are either directly or indirectly observable for the asset or liability as of the reporting date. These inputs are derived principally from, or corroborated by, observable market data.

- Level 3 – Pricing that is based upon inputs that are generally unobservable that are based on the best information available and reflect management's assumptions about how market participants would price the asset or liability.

Assessment of the significance of a particular input to the fair value measurements may require judgment and may affect the valuation of the asset or liability and its placement within the fair value hierarchy. Additional information about fair value measurements is provided in Note 8, Fair Value of Financial Instruments, Note 9, Fair Value Measurements, and Note 13, Pension Plans and Other Postretirement Benefits.

STOCK-BASED COMPENSATION – The Company accounts for share-based compensation arrangements in accordance with ASC Topic 718, *Compensation - Stock Compensation*. The Company measures stock-based compensation awards at fair value at the date of grant and recognizes the compensation cost of the awards over the requisite service period. Forfeitures are recognized in the period they occur. Refer to Note 3, Stock-Based Compensation, for further discussion of the accounting for the Company's stock-based compensation plans.

2. REVENUE

The following tables show revenue disaggregated by source and customer type.

	2022	2021	2020
Spire			
Gas Utility:			
Residential	$ 1,416.6	$ 1,234.0	$ 1,184.3
Commercial & industrial	338.9	586.0	383.0
Transportation	118.0	122.9	115.8
Off-system & other incentive	42.0	152.7	38.4
Other customer revenue	19.9	22.2	26.2
Total revenue from contracts with customers	1,935.4	2,117.8	1,747.7
Changes in accrued revenue under alternative revenue programs	10.7	1.5	4.3
Total Gas Utility operating revenues	1,946.1	2,119.3	1,752.0
Gas Marketing	234.9	96.5	87.9
Other	69.2	67.7	57.8
Total before eliminations	2,250.2	2,283.5	1,897.7
Intersegment eliminations (see Note 14, Information by Operating Segment)	(51.7)	(48.0)	(42.3)
Total Operating Revenues	$ 2,198.5	$ 2,235.5	$ 1,855.4
Spire Missouri			
Residential	$ 1,061.4	$ 882.1	$ 859.6
Commercial & industrial	177.2	436.1	241.4
Transportation	33.3	33.5	32.9
Off-system & other incentive	25.2	145.6	35.1
Other customer revenue	11.1	16.3	22.3
Total revenue from contracts with customers	1,308.2	1,513.6	1,191.3
Changes in accrued revenue under alternative revenue programs	12.8	3.0	2.3
Total Operating Revenues	$ 1,321.0	$ 1,516.6	$ 1,193.6
Spire Alabama			
Residential	$ 291.6	$ 288.0	$ 267.8
Commercial & industrial	119.1	114.9	109.4
Transportation	74.4	78.7	72.9
Off-system & other incentive	16.8	7.1	3.2
Other customer revenue	5.5	1.9	1.9
Total revenue from contracts with customers	507.4	490.6	455.2
Changes in accrued revenue under alternative revenue programs	1.7	3.4	(0.2)
Total Operating Revenues	$ 509.1	$ 494.0	$ 455.0

The Utilities sell natural gas to residential and other customers. The sale of natural gas is governed by the various state utility commissions, which set rates, charges, and terms and conditions of service, collectively included in a "tariff." The performance obligation, which relates to the promise to provide natural gas, is satisfied over time as the customer simultaneously receives and consumes the natural gas, and revenue is recognized accordingly.

The Utilities' transportation revenue relates to the promise to transport the specified quantities of natural gas at tariff rates. This performance obligation is satisfied over time as the gas is transported, and revenue is recognized as invoiced monthly.

The Utilities have alternative revenue programs (ARPs), which represent an agreement between the utility and its regulator, currently consisting of decoupling mechanisms (also known as weather normalization adjustments) and incentive programs (primarily Alabama's Cost Control Measure). When the criteria to recognize additional (or reduced) revenue from ARPs have been met, the Utilities establish a regulatory asset (or liability). When amounts previously recognized for ARPs are billed, the Utilities reduce the regulatory asset (or liability) and increase (or decrease) accounts receivable. Billed amounts, which are part of the overall tariff paid by customers, are included in revenue from contracts with customers, while the change in the related regulatory asset or liability is presented as revenue from ARPs. Depending on whether the beginning accrued ARP balance was a regulatory asset or liability and depending on the size and direction of the current period accrual, the amount presented as revenue from ARPs could be negative.

The Utilities read meters and bill customers on monthly cycles. Spire Missouri, Spire Gulf and Spire Mississippi record their gas utility revenues from gas sales and transportation services on an accrual basis that includes estimated amounts for gas delivered but not yet billed. The accruals for unbilled revenues are reversed in the subsequent accounting period when meters are actually read and customers are billed. Spire Alabama records natural gas distribution revenues in accordance with the tariff established by the APSC. Unbilled revenue is accrued in an amount equal to the related gas cost, as profit margin is not considered earned until billed. Spire's other subsidiaries, including Spire Marketing, record revenues when earned, as the product is delivered or as services are performed.

Gas Marketing's contracts are derivatives. Wholesale contracts (with producers, municipalities, and utility companies) are subject to derivative accounting. Retail contracts (with large commercial and industrial customers) are designated as "normal purchase, normal sale" arrangements and are therefore accounted for as revenue from contracts with customers. The performance obligation is satisfied over time by the transfer of control of natural gas to the customer, and revenue is recognized as invoiced monthly.

Payments are generally required within 30 days of billing, and contracts generally do not have a significant financing component. Spire's revenues are not subject to significant returns, refunds, or warranty obligations.

Spire, Spire Missouri, and Spire Alabama have elected to apply a "right to invoice" practical expedient, recognizing revenue for volumes delivered for which they have a right to invoice, as long as that amount corresponds with the value to the customer. Disclosures about remaining performance obligations are not required because either contracts have an original expected duration of one year or less, or revenue is recognized under the right to invoice practical expedient, or both.

Sales taxes imposed on applicable Spire Alabama and Spire Missouri sales are billed to customers. These amounts are not recorded in the statements of income but are recorded as tax collections payable and included in the "Other" line of the Current Liabilities section of the balance sheets.

Gross receipts taxes associated with the Company's natural gas utility services are imposed on the Company, Spire Missouri, and Spire Alabama and billed to its customers. The expense amounts (shown in the table below) are reported gross in the "Taxes, other than income taxes" line in the statements of income, and corresponding revenues are reported in "Operating Revenues."

	2022	**2021**	**2020**
Spire	$ 109.8	$ 94.0	$ 91.5
Spire Missouri	79.6	64.3	63.5
Spire Alabama	25.5	25.1	23.3

3. STOCK-BASED COMPENSATION

The Spire 2015 Equity Incentive Plan (EIP) was approved by shareholders of Spire on January 29, 2015 and amended on November 9, 2018. The purpose of the EIP is to encourage directors, officers, and key employees of the Company and its subsidiaries to contribute to the Company's success and align their interests with that of shareholders. To accomplish this purpose, the Compensation Committee ("Committee") of Spire's Board of Directors (the "Board") may grant awards under the EIP that may be earned by achieving performance objectives and/or other criteria as determined by the Committee. Under the terms of the EIP, officers and employees of the Company and its subsidiaries, as determined by the Committee, are eligible to be selected for awards. The EIP provides for restricted stock, restricted stock units, qualified and non-qualified stock options, stock appreciation rights, and performance shares payable in stock, cash, or a combination of both. The EIP generally provides a minimum vesting period of at least three years for each type of award, with pro rata vesting permitted during the minimum three-year vesting period. The maximum number of shares reserved for issuance under the EIP is 1,000,000.

The Company issues new shares to satisfy employee restricted stock awards.

Restricted Stock Awards

During fiscal 2022, the Company granted 128,396 performance-contingent restricted share units to executive officers and key employees at a weighted average grant date fair value of $67.43 per share. This number represents the target shares that can be earned pursuant to the terms of the awards. The share units have a performance period ending September 30, 2025. While the participants have no interim voting rights on these share units, dividends accrue during the performance period and are paid to the participants upon vesting but are subject to forfeiture if the underlying share units do not vest.

The number of share units that will ultimately vest is dependent upon the attainment of certain levels of earnings and other strategic goals, as well as the Company's level of total shareholder return (TSR) during the performance period relative to a comparator group of peer companies. This TSR provision is considered a market condition under GAAP and is discussed further below. The maximum amount of shares that can be earned pursuant to the terms of the awards is 200% of the target units granted.

The weighted average grant date fair value of performance-contingent restricted share units granted during fiscal years 2021 and 2020 was $68.69 and $76.19 per share, respectively.

Fiscal 2022 activity of restricted stock units subject to performance and/or market conditions is presented below:

	Units	Weighted Average Grant Date Fair Value Per Unit
Nonvested at September 30, 2021	312,596	$ 74.33
Granted	128,396	$ 67.43
Vested	(91,111)	$ 79.40
Forfeited	(6,357)	$ 69.43
Nonvested at September 30, 2022	343,524	$ 70.14

For the year ended September 30, 2022, the total number of shares that could be issued if all outstanding award grants attain maximum performance payout is 687,048.

During fiscal 2022, the Company granted 62,945 shares of time-vested restricted stock to executive officers and key employees at a weighted average grant date fair value of $63.57 per share. Unless forfeited based on terms of the agreements, these shares will vest in fiscal 2025. In the interim, participants receive full voting rights and dividends, which are not subject to forfeiture. The weighted average grant date fair value of time-vested restricted stock and restricted stock units awarded to employees during fiscal years 2021 and 2020 was $64.29 and $76.13 per share, respectively.

During fiscal 2022, the Company granted 16,290 shares of time-vested restricted stock to non-employee directors at a weighted average grant date fair value of $66.31 per share. These shares vested in fiscal 2022, six months after the grant date. The weighted average grant date fair value of restricted stock awarded to non-employee directors during fiscal years 2021 and 2020 was $62.35 and $84.58 per share, respectively.

Time-vested restricted stock and stock unit activity for fiscal 2022 is presented below:

	Shares/ Units	Weighted Average Grant Date Fair Value Per Share
Nonvested at September 30, 2021	110,300	$ 70.98
Granted	62,945	$ 63.57
Vested	(46,970)	$ 72.67
Forfeited	(4,030)	$ 68.62
Nonvested at September 30, 2022	122,245	$ 66.60

For restricted stock and stock units (performance-contingent and time-vested) that vested during fiscal years 2022, 2021, and 2020, the Company withheld 28,055 shares, 16,787 shares, and 41,353 shares, respectively, at weighted average prices of $63.97, $65.99 and $77.07 per share, respectively, pursuant to elections by employees to satisfy tax withholding obligations. The total fair value of restricted stock (performance-contingent and time-vested) that vested during fiscal years 2022, 2021, and 2020 was $10.1, $6.5, and $9.8, respectively, and the related tax benefit was $3.8, $2.5, and $3.7, respectively. None of the tax benefits have been realized.

The Company allows participants in the EIP the ability to defer a portion or all of their award. As at September 30, 2022, a total of 228,988 shares (at target payout) have been deferred by Participants.

Equity Compensation Costs

Compensation cost for performance-contingent restricted stock and stock unit awards is based upon the probable outcome of the performance conditions. For shares or units that do not vest or that are not expected to vest due to the outcome of the performance conditions (excluding market conditions), no compensation cost is recognized and any previously recognized compensation cost is reversed.

The fair value of awards of performance-contingent and time-vested restricted stock and restricted stock units, not subject to the TSR provision, are estimated using the closing price of the Company's stock on the grant date. For those awards that do not pay dividends during the vesting period, the estimate of fair value is reduced by the present value of the dividends expected to be paid on the Company's common stock during the performance period, discounted using an appropriate U.S. Treasury yield. For shares subject to the TSR provision, the estimated impact of this market condition is reflected in the grant date fair value per share of the awards. Accordingly, compensation cost is not reversed to reflect any actual reductions in the awards that may result from the TSR provision. However, if the Company's TSR during the performance period ranks below the level specified in the award agreements, relative to a comparator group of companies, and the Committee elects not to reduce the award (or reduce by a lesser amount), this election would be accounted for as a modification of the original award and additional compensation cost would be recognized at that time. The grant date fair value of the awards subject to the TSR provision awarded during fiscal years 2022, 2021 and 2020 was valued by a Monte Carlo simulation model that assessed the probabilities of various TSR outcomes. The significant assumptions used in the Monte Carlo simulations are as follows:

	2022	2021	2020
Risk-free interest rate	0.79%	0.22%	1.57%
Expected dividend yield of stock	—	—	—
Expected volatility of stock	32.2%	31.4%	16.8%
Vesting period (in years)	3.0	3.0	3.0

The risk-free interest rate was based on the yield on U.S. Treasury securities matching the vesting period. A zero-percent dividend yield was used, which is mathematically equivalent to the assumption that dividends are reinvested as they are paid. The expected volatility is based on the historical volatility of the Company's stock. Volatility assumptions were also made for each of the companies included in the comparator group. The vesting period is equal to the performance period set forth in the terms of the award.

The amounts of compensation cost recognized for share-based compensation arrangements are presented below:

	2022	2021	2020
Total compensation cost	$ 7.5	$ 16.6	$ 9.4
Compensation cost capitalized	(1.1)	(2.7)	(0.6)
Compensation cost recognized in net income	6.4	13.9	8.8
Income tax benefit recognized in net income	(1.5)	(3.2)	(2.1)
Compensation cost recognized in net income, net of income tax	$ 4.9	$ 10.7	$ 6.7

As of September 30, 2022, there was $11.2 of total unrecognized compensation cost related to non-vested share-based compensation arrangements, which is expected to be recognized over a weighted average period of 1.7 years.

4. EARNINGS PER COMMON SHARE

	2022	2021	2020
Basic Earnings Per Common Share:			
Net Income	$ 220.8	$ 271.7	$ 88.6
Less: Provision for preferred dividends	14.8	14.8	14.8
Income allocated to participating securities	0.3	0.4	0.1
Net Income Available to Common Shareholders	$ 205.7	$ 256.5	$ 73.7
Weighted Average Common Shares Outstanding (in millions)	52.0	51.6	51.2
Basic Earnings Per Share of Common Stock	$ 3.96	$ 4.97	$ 1.44
Diluted Earnings per Common Share:			
Net Income	$ 220.8	$ 271.7	$ 88.6
Less: Provision for preferred dividends	14.8	14.8	14.8
Income allocated to participating securities	0.3	0.4	0.1
Net Income Available to Common Shareholders	$ 205.7	$ 256.5	$ 73.7
Weighted Average Common Shares Outstanding (in millions)	52.0	51.6	51.2
Dilutive Effect of Restricted Stock and Restricted Stock Units (in millions)*	0.1	0.1	0.1
Weighted Average Diluted Common Shares (in millions)	52.1	51.7	51.3
Diluted Earnings Per Share of Common Stock	$ 3.95	$ 4.96	$ 1.44
* Calculation excludes certain outstanding common shares (shown in millions by period at the right) attributable to stock units subject to performance or market conditions and restricted stock, which could have a dilutive effect in the future	0.1	0.1	0.1

5. SHAREHOLDERS' EQUITY

Spire

Preferred Stock

At September 30, 2022 and 2021, Spire had authorized 5,000,000 shares of preferred stock.

On May 21, 2019, Spire completed the public offering of 10,000,000 depositary shares (the "Depositary Shares"), each representing a 1/1,000th interest in a share of the Company's 5.90% Series A Cumulative Redeemable Perpetual Preferred Stock, par value $25.00 per share, with a liquidation preference of $25,000 per share (the "Preferred Stock"). The transaction resulted in $242.0 of net proceeds, after deducting commissions and sale expenses, which proceeds were used to (i) refinance long-term and short-term Spire debt and (ii) fund capital expenditures at both the Utilities and Spire's gas-related businesses.

Dividends on the Preferred Stock, when declared by the Board, are payable on the liquidation preference amount, on a cumulative basis, quarterly in arrears on the 15th day of February, May, August and November of each year, beginning on August 15, 2019. Dividends are payable out of amounts legally available for the payment of dividends at an annual rate equal to 5.90% of the liquidation preference per share of Preferred Stock (equivalent to $25.00 per Depositary Share). Dividends accumulate daily and are cumulative from May 21, 2019.

Under the terms of the Preferred Stock, the Company's ability to declare or pay dividends on, or purchase or redeem, shares of its common stock or any class or series of capital stock of the Company that rank junior to the Preferred Stock are subject to certain restrictions in the event that the Company does not declare and pay the full cumulative dividends on the Preferred Stock through the most recently completed quarterly dividend period.

Spire may, at its option, redeem the Preferred Stock (i) in whole, but not in part, at any time prior to August 15, 2024, within 120 days after a ratings event where a rating agency amends, clarifies or changes the criteria it uses to assign equity credit for securities such as the Preferred Stock, at a redemption price in cash equal to $25,500 per share, or (ii) in whole or in part, from time to time, on or after August 15, 2024, at a redemption price in cash equal to $25,000 per share, plus, in each case, all accumulated and unpaid dividends (whether declared or not) up to such redemption date.

Shareholders of the Preferred Stock generally have no voting rights with respect to matters that generally require the approval of voting stockholders. The limited voting rights of holders of the Preferred Stock include the right to vote on certain matters that may affect the preference or special rights of the Preferred Stock. In addition, if and whenever dividends on any shares of Preferred Stock have not been declared and paid for at least six dividend periods, whether or not consecutive, the number of directors then constituting the Board shall automatically be increased by two (to be elected by the holders of the Preferred Stock) until all accumulated and unpaid dividends on the Preferred Stock have been paid in full.

Equity Units

In February 2021, Spire issued 3.5 million equity units, initially in the form of Corporate Units, for an aggregate stated amount of $175.0, resulting in net proceeds (after underwriting fees and other issuance costs) of $169.3. Each "Corporate Unit" has a stated amount of fifty dollars and consists of (i) a stock purchase contract and (ii) a 1/20, or 5%, undivided beneficial ownership interest in one thousand dollars principal amount of Spire's 2021 Series A 0.75% Remarketable Senior Notes due March 1, 2026 (RSNs). The RSNs are pledged as collateral to secure the holder's obligation under the related stock purchase contracts. Each stock purchase contract obligates the holder to purchase, and Spire to issue and deliver, on March 1, 2024, for a price of fifty dollars in cash, a variable number of shares of its common stock as follows (subject to anti-dilution adjustments).

If the applicable market value* per share of Spire common stock is:	Number of shares to be purchased per stock purchase contract is:
Equal to or greater than $78.6906 ("threshold appreciation price")	0.6354 ("minimum settlement rate")
Less than $78.6906, but greater than $64.24	$50.00 ÷ applicable market value*
Less than or equal to $64.24 ("reference price")	0.7783 ("maximum settlement rate")

*Based on the volume-weighted average price of Spire common stock during the 20 trading days before settlement.

If a holder elects to settle purchase contracts early, the holder would pay fifty dollars per unit and receive 0.6354 shares per unit.

The Company makes quarterly interest payments on the RSNs at the rate of 0.75% per year and quarterly contract adjustment payments on the stock purchase contracts at the rate of 6.75%. The RSNs and the contract adjustment payments are structurally subordinated to all liabilities of Spire's subsidiaries.

At issuance, the Company recorded the $35.0 present value of the stock purchase contract payments as a liability (reflected in "Other" current and noncurrent liabilities on the balance sheet) offset by a charge to additional paid-in capital in equity. This noncash financing activity has been excluded from the statement of cash flows. Interest payments on the RSNs are recorded as interest expense and stock purchase contract payments are charged against the liability. Accretion of the stock purchase contract liability is recorded as imputed interest expense. In calculating diluted EPS, the Company applies the treasury stock method to the Corporate Units. These securities have not had an effect on diluted EPS.

In order to secure funds necessary for the holders to pay the purchase price of the common stock on the purchase contract settlement date, the remarketing agent will remarket the RSNs on behalf of the current holders to new third-party investors. Following any successful remarketing of the RSNs, the interest rate on the RSNs will be reset, interest will be payable on a semi-annual basis, and Spire will cease to have the option to redeem the RSNs, other than in connection with the occurrence or continuance of certain special events.

ATM Program

On February 6, 2019, Spire entered into an “at-the-market” (ATM) equity distribution agreement pursuant to which the Company may offer and sell, from time to time, shares of its common stock pursuant to Spire’s universal shelf registration statement and a prospectus supplement. Under this program, a total of 626,249 shares with an aggregate offering price of $47.8 were issued in fiscal 2019 and 2020, and 354,000 shares with an aggregate offering price of $23.5 were issued in the second quarter of fiscal 2022. On April 28, 2022, Spire’s Board of Directors approved a new authorization for the sale of additional shares with an aggregate offering price of up to $200.0 before the May 2025 expiration of the new universal shelf registration statement on Form S-3 filed in May 2022, under which a total of 365,625 shares with an aggregate offering price of $27.7 were issued in the third quarter of fiscal 2022.

Other Equity Information

Spire has a shelf registration statement on Form S-3 on file with the U.S. Securities and Exchange Commission (SEC) for the issuance and sale of up to 250,000 shares of common stock under its Dividend Reinvestment and Direct Stock Purchase Plan. There were 158,535 and 153,190 shares at September 30, 2022 and November 11, 2022, respectively, remaining available for issuance under this Form S-3. Spire also has a universal shelf registration statement on Form S-3 on file with the SEC for the issuance of various equity and debt securities, which expires on May 9, 2025.

Spire Missouri

Substantially all of Spire Missouri’s plant is subject to the liens of its first mortgage bonds. The mortgage contains several restrictions on Spire Missouri’s ability to pay cash dividends on its common stock or to make loans to its parent company. These mortgage restrictions are applicable regardless of whether the stock is publicly held or held solely by Spire Missouri’s parent company. Under the most restrictive of these provisions, no cash dividend may be declared or paid if, after the dividend, the aggregate net amount spent for all dividends after September 30, 1953 would exceed a maximum amount determined by a formula set out in the mortgage. Under that formula, the maximum amount is the sum of $8.0 plus earnings applicable to common stock (adjusted for stock repurchases and issuances) for the period from September 30, 1953 to the last day of the quarter before the declaration or payment date for the dividends. As of September 30, 2022 and 2021, the amount under the mortgage’s formula that was available to pay dividends was $1,579.4 and $1,413.4, respectively. Thus, all of Spire Missouri’s retained earnings were free from such dividend restrictions as of those dates.

Spire Missouri has a universal shelf registration statement on Form S-3 on file with the SEC for the issuance of various equity and debt securities, which expires on May 9, 2025. Effective March 5, 2022, Spire Missouri was authorized by the MoPSC to issue conventional term loans, first mortgage bonds, unsecured debt, preferred stock and common stock in an aggregate amount of up to $800.0 for financings placed any time before December 31, 2024. As of September 30, 2022, the entire amount remained available under this authorization.

At September 30, 2022 and 2021, Spire Missouri had authorized 1,480,000 shares of preferred stock, but none were issued and outstanding.

Spire Alabama

At September 30, 2022 and 2021, Spire Alabama had authorized 120,000 shares of preferred stock, but none were issued and outstanding.

Accumulated Other Comprehensive Income

The components of accumulated other comprehensive income (AOCI), net of income taxes, recognized in the balance sheets at September 30 were as follows:

	Net Unrealized Gain (Loss) on Cash Flow Hedges	Defined Benefit Pension and Other Postretirement Benefit Plans	Net Unrealized Gain (Loss) on Available-for-Sale Debt Securities	Total
Spire				
Balance at September 30, 2020	$ (38.4)	$ (2.9)	$ 0.1	$ (41.2)
Other comprehensive income (loss)	46.3	(1.3)	(0.2)	44.8
Balance at September 30, 2021	7.9	(4.2)	(0.1)	3.6
Other comprehensive income (loss)	42.5	1.5	(0.4)	43.6
Balance at September 30, 2022	$ 50.4	$ (2.7)	$ (0.5)	$ 47.2
Spire Missouri				
Balance at September 30, 2020	$ —	$ (2.9)	$ —	$ (2.9)
Other comprehensive loss	—	(1.3)	—	(1.3)
Balance at September 30, 2021	—	(4.2)	—	(4.2)
Other comprehensive income	—	1.5	—	1.5
Balance at September 30, 2022	$ —	$ (2.7)	$ —	$ (2.7)

Income tax expense (benefit) recorded for items of other comprehensive income (loss) reported in the statements of comprehensive income is calculated by applying statutory federal, state, and local income tax rates applicable to ordinary income. The tax rates applied to individual items of other comprehensive income (loss) are similar within each reporting period. For the periods presented, Spire Alabama had no AOCI balances.

6. LONG-TERM DEBT

The composition of long-term debt as of September 30 is shown in the following tables.

	2022	2021
Spire		
3.31% Notes Payable, due December 15, 2022	$ 25.0	$ 25.0
3.54% Senior Notes, due February 27, 2024	150.0	150.0
0.75% Remarketable Senior Notes, due March 1, 2026	175.0	175.0
3.13% Senior Notes, due September 1, 2026	130.0	130.0
3.93% Senior Notes, due March 15, 2027	100.0	100.0
4.70% Senior Notes, due August 15, 2044	250.0	250.0
Total principal of Spire Missouri long-term debt (see below)	1,648.0	1,348.0
Total principal of Spire Alabama long-term debt (see below)	575.0	625.0
Other subsidiaries' long-term debt:		
5.00% First Mortgage Bonds, due September 30, 2031	42.0	42.0
2.95% Notes, with annual principal payments through December 2034	123.9	129.6
3.52% First Mortgage Bonds, due September 30, 2049	40.0	40.0
Total principal of long-term debt	3,258.9	3,014.6
Less: Unamortized discounts and debt issuance costs	(19.2)	(19.7)
Less: Current portion	(281.2)	(55.8)
Long-term debt, excluding current portion	$ 2,958.5	$ 2,939.1
Spire Missouri		
First Mortgage Bonds:		
3.40% Series, due August 15, 2023	$ 250.0	$ 250.0
Floating Rate Series, due December 2, 2024	300.0	—
3.40% Series, due March 15, 2028	45.0	45.0
7.00% Series, due June 1, 2029	19.3	19.3
2.84% Series, due November 15, 2029	275.0	275.0
7.90% Series, due September 15, 2030	30.0	30.0
3.68% Series, due September 15, 2032	50.0	50.0
6.00% Series, due May 1, 2034	99.3	99.3
6.15% Series, due June 1, 2036	54.5	54.5
4.63% Series, due August 15, 2043	99.9	99.9
4.23% Series, due September 15, 2047	70.0	70.0
3.30% Series, due June 1, 2051	305.0	305.0
4.38% Series, due September 15, 2057	50.0	50.0
Total principal of Spire Missouri long-term debt	1,648.0	1,348.0
Less: Unamortized discounts and debt issuance costs	(10.3)	(9.6)
Less: Current portion	(250.0)	—
Spire Missouri long-term debt, excluding current portion	$ 1,387.7	$ 1,338.4
Spire Alabama		
3.86% Notes, due December 22, 2021	$ —	$ 50.0
3.21% Notes, due September 15, 2025	35.0	35.0
2.88% Notes, due December 1, 2029	100.0	100.0
2.04% Notes, due December 15, 2030	150.0	150.0
5.90% Notes, due January 15, 2037	45.0	45.0
4.31% Notes, due December 1, 2045	80.0	80.0
3.92% Notes, due January 15, 2048	45.0	45.0
4.64% Notes, due January 15, 2049	90.0	90.0
4.02% Notes, due January 15, 2058	30.0	30.0
Total principal of Spire Alabama long-term debt	575.0	625.0
Less: Unamortized discounts and debt issuance costs	(3.5)	(3.8)
Less: Current portion	—	(50.0)
Spire Alabama long-term debt, excluding current portion	$ 571.5	$ 571.2

Spire Missouri's $300.0 of first mortgage bonds due December 2, 2024 are secured equally with all its other first mortgage bonds. Interest is payable quarterly in arrears at a floating rate based on the compounded secured overnight financing rate plus 50 basis points, with a maximum rate of the lesser of 8% or the maximum rate then permitted by applicable law.

Maturities of long-term debt for Spire on a consolidated basis, Spire Missouri and Spire Alabama for the five fiscal years after September 30, 2022 are as follows:

	2023	2024	2025	2026	2027
Spire	$ 281.2	$ 156.6	$ 342.0	$ 312.5	$ 108.1
Spire Missouri	250.0	—	300.0	—	—
Spire Alabama	—	—	35.0	—	—

The long-term debt agreements of Spire, Spire Missouri and Spire Alabama contain customary financial covenants and default provisions. As of September 30, 2022, there were no events of default under these financial covenants.

After fiscal year end, on October 13, 2022, Spire Alabama issued $90.0 of notes due October 15, 2029, bearing interest at 5.32% and $85.0 of notes due October 15, 2032, bearing interest at 5.41%. Interest is payable semi-annually. The notes are senior unsecured obligations and rank equal in right to payment with all other senior unsecured indebtedness of Spire Alabama. Also on October 13, 2022, Spire Gulf issued $30.0 of first mortgage bonds due October 15, 2037, bearing interest at 5.61% payable semi-annually. The bonds rank equal in right to payment with the other first mortgage bonds issued by Spire Gulf. The bonds were issued under a supplemental indenture with collateral fall away provisions whereby, under certain conditions, Spire Gulf may elect to exchange the bonds, which are secured, for unsecured notes.

Spire

At September 30, 2022, including the current portion but excluding unamortized discounts and debt issuance costs, Spire had long-term debt totaling $3,258.9, of which $1,648.0 was issued by Spire Missouri, $575.0 was issued by Spire Alabama and $205.9 was issued by other subsidiaries. Except for $300.0 of Spire Missouri floating-rate bonds, all long-term debt bears fixed rates and is subject to changes in fair value as market interest rates change. However, increases and decreases in fair value would impact earnings and cash flows only if the Company were to reacquire any of these issues in the open market prior to maturity. Under GAAP applicable to the Utilities' regulated operations, losses or gains on early redemption of long-term debt would typically be deferred as regulatory assets or regulatory liabilities and amortized over a future period. Interest expense shown on Spire's consolidated statement of income is net of capitalized interest totaling $4.5, $4.4 and $5.8 for the years ended September 30, 2022, 2021 and 2020, respectively.

As indicated in Note 5, Shareholders' Equity, Spire has a shelf registration statement on Form S-3 on file with the SEC for the issuance of equity and debt securities.

Spire Missouri

At September 30, 2022, including the current portion but excluding unamortized discounts and debt issuance costs, Spire Missouri had long-term debt totaling $1,648.0. Except for $300.0 of floating-rate bonds, all long-term debt bears fixed rates and is subject to changes in fair value as market interest rates change. Interest expense shown on Spire Missouri's statement of comprehensive income is net of capitalized interest totaling $0.6, $0.2 and $0.8 for the years ended September 30, 2022, 2021 and 2020, respectively.

As indicated in Note 5, Shareholders' Equity, Spire Missouri has a shelf registration on Form S-3 on file with the SEC for issuance of equity and debt securities, which expires on May 9, 2025. Effective March 5, 2022, Spire Missouri was authorized by the MoPSC to issue conventional term loans, first mortgage bonds, unsecured debt, preferred stock and common stock in an aggregate amount of up to $800.0 for financings placed any time before December 31, 2024. As of September 30, 2022, the entire amount remained available under this authorization.

Substantially all of Spire Missouri's plant is subject to the liens of its first mortgage bonds. The mortgage contains several restrictions on Spire Missouri's ability to pay cash dividends on its common stock, which are described in Note 5, Shareholders' Equity.

Spire Alabama

At September 30, 2022, including the current portion (none) but excluding unamortized debt issuance costs, Spire Alabama had fixed-rate long-term debt totaling $575.0. While these long-term debt issues are fixed-rate, they are subject to changes in fair value as market interest rates change. Interest expense shown on Spire Alabama's statement of income is net of capitalized interest totaling $3.2, $3.2 and $1.9 for the years ended September 30, 2022, 2021 and 2020, respectively.

Spire Alabama has no standing authority to issue long-term debt and must petition the APSC for each planned issuance.

7. NOTES PAYABLE AND CREDIT AGREEMENTS

Spire, Spire Missouri and Spire Alabama have a syndicated revolving credit facility pursuant to a loan agreement with 12 banks, which was amended July 22, 2022, to increase the commitment and sublimits and extend the agreement through July 22, 2027. The amended loan agreement has an aggregate credit commitment of $1,300.0, including sublimits of $450.0 for the Spire holding company, $575.0 for Spire Missouri and $275.0 for Spire Alabama. These sublimits may be reallocated from time to time among the three borrowers within the $1,300.0 aggregate commitment, with commitment fees and interest margins applied for each borrower relative to its credit rating, as well as sustainability rate adjustments based on Spire's DART ("Days Away Restricted or Transferred") rate and methane emissions reductions. The Spire holding company may use its line to provide for the funding needs of various subsidiaries. The agreement also contains financial covenants limiting each borrower's consolidated total debt, including short-term debt, to no more than 70% of its total capitalization. As defined in the line of credit, on September 30, 2022, total debt was less than or equal to 60% of total capitalization for each borrower. There were no borrowings against this credit facility as of September 30, 2022 and 2021.

Spire has a commercial paper program ("CP Program") pursuant to which it may issue short-term, unsecured commercial paper notes. Amounts available under the CP Program may be borrowed, repaid and re-borrowed from time to time, with the aggregate face or principal amount of the notes outstanding under the CP Program at any time not to exceed $1,300.0. The notes may have maturities of up to 365 days from date of issue.

In March 2021, Spire Missouri entered into a loan agreement with several banks for a $250.0, 364-day unsecured term loan with an interest rate based on LIBOR plus 65 basis points. The loan was repaid in March 2022.

Information about short-term borrowings, including Spire Missouri's and Spire Alabama's borrowings from Spire, is presented in the following table. As of September 30, 2022, $777.8 of Spire's short-term borrowings were used to support lending to the Utilities.

	Spire (Parent Only)	Spire Missouri		Spire Alabama	Spire
	CP Program	Term Loan	Spire Note	Spire Note	Consol- idated
Year Ended September 30, 2022					
Highest borrowings outstanding	$ 1,079.0	$ 250.0	$ 456.6	$ 265.2	$ 1,079.0
Lowest borrowings outstanding	408.0	—	43.2	38.4	462.5
Weighted average borrowings	636.2	113.0	244.9	152.6	749.2
Weighted average interest rate	1.2%	0.8%	0.4%	0.5%	1.1%
As of September 30, 2022					
Borrowings outstanding	$ 1,037.5	$ —	$ 445.3	$ 260.9	$ 1,037.5
Weighted average interest rate	3.3%	0.0%	3.3%	3.3%	3.3%
As of September 30, 2021					
Borrowings outstanding	$ 422.0	$ 250.0	$ 240.9	$ 49.0	$ 672.0
Weighted average interest rate	0.2%	0.7%	0.2%	0.2%	0.4%

8. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amounts and estimated fair values of financial instruments not measured at fair value on a recurring basis were as follows:

	Carrying Amount	Fair Value	Classification of Estimated Fair Value: Quoted Prices in Active Markets (Level 1)	Classification of Estimated Fair Value: Significant Observable Inputs (Level 2)
Spire				
As of September 30, 2022				
Cash and cash equivalents	$ 6.5	$ 6.5	$ 6.5	$ —
Notes payable	1,037.5	1,037.5	—	1,037.5
Long-term debt, including current portion	3,239.7	2,851.8	—	2,851.8
As of September 30, 2021				
Cash and cash equivalents	$ 4.3	$ 4.3	$ 4.3	$ —
Notes payable	672.0	672.0	—	672.0
Long-term debt, including current portion	2,994.9	3,375.9	—	3,375.9
Spire Missouri				
As of September 30, 2022				
Notes payable - associated companies	$ 445.3	$ 445.3	$ —	$ 445.3
Long-term debt, including current portion	1,637.7	1,473.9	—	1,473.9
As of September 30, 2021				
Note Payable	$ 250.0	$ 250.0	$ —	$ 250.0
Notes payable - associated companies	240.9	240.9	—	240.9
Long-term debt	1,338.4	1,540.4	—	1,540.4
Spire Alabama				
As of September 30, 2022				
Cash and cash equivalents	$ 2.4	$ 2.4	$ 2.4	$ —
Notes payable - associated companies	260.9	260.9	—	260.9
Long-term debt	571.5	485.0	—	485.0
As of September 30, 2021				
Notes payable - associated companies	$ 49.0	$ 49.0	$ —	$ 49.0
Long-term debt, including current portion	621.2	707.5	—	707.5

9. FAIR VALUE MEASUREMENTS

The information presented below categorizes the assets and liabilities in the balance sheets that are accounted for at fair value on a recurring basis in periods subsequent to initial recognition.

The mutual funds included in Level 1 are valued based on exchange-quoted market prices of individual securities. The mutual funds included in Level 2 are valued based on the closing net asset value per unit.

Derivative instruments included in Level 1 are valued using quoted market prices on the NYMEX or the Intercontinental Exchange (ICE). Derivative instruments classified in Level 2 include physical commodity derivatives that are valued using broker or dealer quotation services whose prices are derived principally from, or are corroborated by, observable market inputs. Also included in Level 2 are certain derivative instruments that have values that are similar to, and correlate with, quoted prices for exchange-traded instruments in active markets. Derivative instruments included in Level 3 are valued using generally unobservable inputs that are based upon the best information available and reflect management's assumptions about how market participants would price the asset or liability. There were no Level 3 balances as of September 30, 2022 or 2021. The Company's and the Utilities' policy is to recognize transfers between the levels of the fair value hierarchy, if any, as of the beginning of the interim reporting period in which circumstances change or events occur to cause the transfer.

The mutual funds are included in "Other investments" on the Company's balance sheets and in "Other Property and Investments" on Spire Missouri's balance sheets. Changes in their recurring valuations are recorded as unrealized investment gains or losses in the corresponding periodic income statement. Derivative assets and liabilities, including receivables and payables associated with cash margin requirements, are presented net on the balance sheets when a legally enforceable netting agreement exist between the Company, Spire Missouri or Spire Alabama and the counterparty to the derivative contract. For additional information on derivative instruments, see Note 10, Derivative Instruments and Hedging Activities.

Spire

	Quoted Prices in Active Markets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Effects of Netting and Cash Margin Receivables /Payables	Total
As of September 30, 2022					
ASSETS					
Gas Utility:					
U.S. stock/bond mutual funds	$ 19.1	$ —	$ —	$ —	$ 19.1
NYMEX/ICE natural gas contracts	57.8	—	—	(57.8)	—
Gas Marketing:					
NYMEX/ICE natural gas contracts	91.8	—	—	(91.8)	—
Natural gas commodity contracts	56.6	—	—	(4.0)	52.6
Other:					
U.S. stock/bond mutual funds	29.3	—	—	—	29.3
Interest rate swaps	63.6	—	—	—	63.6
Total	$ 318.2	$ —	$ —	$ (153.6)	$ 164.6
LIABILITIES					
Gas Utility:					
NYMEX/ICE natural gas contracts	$ 30.7	$ —	$ —	$ (30.7)	$ —
Gas Marketing:					
NYMEX/ICE natural gas contracts	82.3	—	—	(82.3)	—
Natural gas commodity contracts	65.5	—	—	(4.0)	61.5
Total	$ 178.5	$ —	$ —	$ (117.0)	$ 61.5
As of September 30, 2021					
ASSETS					
Gas Utility:					
U.S. stock/bond mutual funds	$ 23.8	$ —	$ —	$ —	$ 23.8
NYMEX/ICE natural gas contracts	104.0	—	—	(104.0)	—
Gas Marketing:					
NYMEX/ICE natural gas contracts	—	114.7	—	(93.7)	21.0
Natural gas commodity contracts	—	35.2	—	(5.5)	29.7
Other:					
U.S. stock/bond mutual funds	26.2	—	—	—	26.2
Interest rate swaps	12.6	—	—	(5.2)	7.4
Total	$ 166.6	$ 149.9	$ —	$ (208.4)	$ 108.1
LIABILITIES					
Gas Utility:					
NYMEX/ICE natural gas contracts	$ 0.3	$ —	$ —	$ (0.3)	$ —
Gas Marketing:					
NYMEX/ICE natural gas contracts	—	62.0	—	(62.0)	—
Natural gas commodity contracts	—	96.7	—	(5.5)	91.2
Other:					
Interest rate swaps	5.7	—	—	(5.2)	0.5
Total	$ 6.0	$ 158.7	$ —	$ (73.0)	$ 91.7

Spire Missouri

	Quoted Prices in Active Markets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Effects of Netting and Cash Margin Receivables /Payables	Total
As of September 30, 2022					
ASSETS					
U.S. stock/bond mutual funds	$ 19.1	$ —	$ —	$ —	$ 19.1
NYMEX/ICE natural gas contracts	57.8	—	—	(57.8)	—
Total	$ 76.9	$ —	$ —	$ (57.8)	$ 19.1
LIABILITIES					
NYMEX/ICE natural gas contracts	$ 30.7	$ —	$ —	$ (30.7)	$ —
As of September 30, 2021					
ASSETS					
U.S. stock/bond mutual funds	$ 23.8	$ —	$ —	$ —	$ 23.8
NYMEX/ICE natural gas contracts	104.0	—	—	(104.0)	—
Total	$ 127.8	$ —	$ —	$ (104.0)	$ 23.8
LIABILITIES					
NYMEX/ICE natural gas contracts	$ 0.3	$ —	$ —	$ (0.3)	$ —

Spire Alabama

Spire Alabama occasionally utilizes a gasoline derivative program to stabilize the cost of fuel used in operations. As of September 30, 2022 and September 30, 2021, there were no gasoline derivatives outstanding.

10. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Spire

Spire Missouri has a risk management policy to utilize various derivatives, including futures contracts, exchange-traded options and swaps for the explicit purpose of managing price risk associated with purchasing and delivering natural gas on a regular basis to customers in accordance with its tariffs. The objective of this policy is to limit Spire Missouri's exposure to natural gas price volatility and to manage, hedge and mitigate substantial price risk. Further discussion of this policy can be found in the Spire Missouri section.

From time to time Spire Missouri and Spire Alabama purchase NYMEX futures and options contracts to help stabilize operating costs associated with forecasted purchases of gasoline and diesel fuels used to power vehicles and equipment. Further information on these derivatives can be found in the Spire Missouri and Spire Alabama sections, respectively.

In the course of its business, Spire's gas marketing subsidiary, Spire Marketing (including a wholly owned subsidiary), enters into commitments associated with the purchase or sale of natural gas. Certain of Spire Marketing's derivative natural gas contracts are designated as normal purchases or normal sales and, as such, are excluded from the scope of ASC Topic 815 and are accounted for as executory contracts on an accrual basis. Any of Spire Marketing's derivative natural gas contracts that are not designated as normal purchases or normal sales are accounted for at fair value. At September 30, 2022, the fair values of 492.2 million MMBtu of non-exchange-traded natural gas commodity contracts were reflected in the Consolidated Balance Sheet. Of these contracts, 347.8 million MMBtu will settle during fiscal 2023, and 88.8 million MMBtu, 47.5 million MMBtu, 7.0 million MMBtu, and 1.1 million MMBtu will settle during fiscal years 2024, 2025, 2026 and 2027, respectively. These contracts have not been designated as hedges; therefore, changes in the fair value of these contracts are reported in earnings each period.

Furthermore, Spire Marketing manages the price risk associated with its fixed-priced commitments by either closely matching the offsetting physical purchase or sale of natural gas at fixed prices or through the use of NYMEX or ICE futures, swap, and option contracts to lock in margins.

At September 30, 2022, Spire Marketing's unmatched fixed-price positions were not material to Spire's financial position or results of operations. Spire Marketing's NYMEX and ICE natural gas futures, swap and option contracts used to lock in margins may be designated as cash flow hedges of forecasted transactions for financial reporting purposes.

In the second quarter of 2020, the Company entered into multiple ten-year interest rate swaps with fixed interest rates ranging from 0.934% to 1.2975% for a total notional amount of $75.0 to protect itself against adverse movements in interest rates on future interest rate payments. The Company recorded a $9.8 mark-to-market gain in accumulated other comprehensive income on these swaps for the twelve months ended September 30, 2022. In the third quarter of 2021 the Company entered into multiple ten-year interest rate swaps with fixed interest rates ranging from 2.008% to 2.1075% for a total notional amount of $150.0 to protect itself against adverse movements in interest rates on future interest rate payments. The Company recorded a $17.9 mark-to-market gain in accumulated other comprehensive income on these swaps for the twelve months ended September 30, 2022.

In the fourth quarter of 2021, the Company entered into two swap contracts. Both contracts are ten-year interest rate swaps; the first swap has a notional amount of $50.0 with a fixed interest rate of 1.597%, while the second swap has a notional amount of $50.0 with a fixed interest rate of 1.821%. The Company recorded a $5.7 mark-to-market gain in accumulated other comprehensive income on these swaps for the twelve months ended September 30, 2022.

In the first quarter of fiscal 2022, the Company entered into a ten-year interest rate swap contract with a notional amount of $50.0 with a fixed interest rate of 1.4918%. The Company recorded a $7.0 mark-to-market gain to accumulated other comprehensive income on this swap for the twelve months ended September 30, 2022.

In the second quarter of fiscal 2022, the Company entered into multiple ten-year interest rate swap contracts with a cumulative total notional amount of $150.0 with fixed interest rates ranging from 1.64750% to 1.7460%. The Company recorded a $16.2 mark-to-market gain to accumulated other comprehensive income on these swaps for the twelve months ended September 30, 2022.

As of September 30, 2022, the Company has recorded through other comprehensive income a cumulative mark-to-market net asset of $63.6 on open swaps. The Company's and Spire Missouri's exchange-traded/cleared derivative instruments consist primarily of NYMEX and ICE positions. The NYMEX is the primary national commodities exchange on which natural gas derivatives are traded. Open NYMEX and ICE natural gas futures and swap positions at September 30, 2022 and 2021 were as follows:

	September 30, 2022		**September 30, 2021**	
Gas Marketing	**Notional (MMBtu millions)**	**Maximum Term (Months)**	**Notional (MMBtu millions)**	**Maximum Term (Months)**
Natural gas futures purchased	76.3	54	103.3	51
Natural gas options purchased, net	3.7	12	7.1	15
Natural gas basis swaps purchased	61.7	39	101.7	27
Gas Utility				
Natural gas futures purchased	13.0	12	52.8	12

At September 30, 2022, Spire Missouri also had 23.4 MMBtu of other price mitigation in price mitigation in place through the use of NYMEX natural gas option-based strategies.

Derivative instruments designated as cash flow hedges of forecasted transactions are recognized on the balance sheets of the Company at fair value, and the change in fair value of the effective portion of these hedge instruments is recorded, net of income tax, in other comprehensive income or loss (OCI). Accumulated other comprehensive income or loss (AOCI) is a component of Total Common Stock Equity. Amounts are reclassified from AOCI into earnings when the hedged items affect net income, using the same revenue or expense category that the hedged item impacts. Based on market prices at September 30, 2022, it is expected that an immaterial amount of unrealized gains will be reclassified into the Consolidated Statements of Income of the Company during the next twelve months. Cash flows from hedging transactions are classified in the same category as the cash flows from the items that are being hedged in the Consolidated Statements of Cash Flows.

Effect of Derivative Instruments on the Consolidated Statements of Income and Comprehensive Income

	Location of Gain (Loss) Recorded in Income	2022	2021	2020
Derivatives in Cash Flow Hedging Relationships				
Effective portion of gain (loss) recognized in OCI on derivatives:				
Interest rate swaps		$ 56.7	$ 61.2	$ (8.9)
Effective portion of (loss) gain reclassified from AOCI to income:				
Interest rate swaps	Interest Expense	$ (1.2)	$ (1.3)	$ (3.2)
Derivatives Not Designated as Hedging Instruments*				
Gain (Loss) recognized in income on derivatives:				
Natural gas commodity contracts	Operating Expenses: Natural Gas	$ 52.6	$ 54.1	$ 9.2
NYMEX / ICE natural gas contracts	Operating Expenses: Natural Gas	43.3	(77.5)	(11.8)
Total		$ 95.9	$ (23.4)	$ (2.6)

* Gains and losses on Spire Missouri's natural gas derivative instruments, which are not designated as hedging instruments for financial reporting purposes, are deferred pursuant to the Missouri Utilities' PGA clauses and initially recorded as regulatory assets or regulatory liabilities. These gains and losses are excluded from the table above because they have no direct impact on the statements of income. Such amounts are recognized in the statements of income as a component of natural gas operating expenses when they are recovered through the PGA clause and reflected in customer billings.

Fair Value of Derivative Instruments in the Consolidated Balance Sheets

	Derivative Assets*		Derivative Liabilities*	
September 30, 2022	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
Derivatives designated as hedging instruments				
Other: Interest rate swaps	Current Assets: Other	$ 63.6	Current Liabilities: Other	$ —
Subtotal		63.6		—
Derivatives not designated as hedging instruments				
Gas Utility:				
Natural gas contracts	Current Assets: Other	57.8	Current Liabilities: Other	30.7
Gas Marketing:				
NYMEX / ICE natural gas contracts	Current Assets: Other	79.2	Current Liabilities – Other	71.5
	Deferred Charges and Other Assets: Other	12.7	Deferred Credits and Other Liabilities: Other	10.8
Natural gas commodity	Current Assets: Other	53.4	Current Liabilities – Other	55.1
	Deferred Charges and Other Assets: Other	3.1	Deferred Credits and Other Liabilities: Other	10.4
Subtotal		206.2		178.5
Total derivatives		$ 269.8		$ 178.5
September 30, 2021				
Derivatives designated as hedging instruments				
Other: Interest rate swaps	Current Assets: Other	$ 12.6	Current Liabilities: Other	$ 5.7
Subtotal		12.6		5.7
Derivatives not designated as hedging instruments				
Gas Utility:				
Natural gas contracts	Current Assets: Other	104.0	Current Liabilities: Other	0.3
Gas Marketing:				
NYMEX / ICE natural gas contracts	Current Assets: Other	93.9	Current Liabilities – Other	50.1
	Deferred Charges and Other Assets: Other	20.8	Deferred Credits and Other Liabilities: Other	11.9
Natural gas commodity	Current Assets: Other	34.1	Current Liabilities – Other	82.5
	Deferred Charges and Other Assets: Other	1.1	Deferred Credits and Other Liabilities: Other	14.2
Subtotal		253.9		159.0
Total derivatives		$ 266.5		$ 164.7

* The fair values of Derivative Assets and Derivative Liabilities exclude the fair value of cash margin receivables or payables with counterparties subject to netting arrangements. Fair value amounts of derivative contracts (including the fair value amounts of cash margin receivables and payables) for which there is a legal right to set off are presented net on the balance sheets. As such, the gross balances presented in the table above are not indicative of the Company's net economic exposure. Refer to Note 9, Fair Value Measurements, for information on the valuation of derivative instruments.

Following is a reconciliation of the amounts in the tables above to the amounts presented in the Consolidated Balance Sheets:

	2022	2021
Fair value of derivative assets presented above	$ 269.8	$ 266.5
Fair value of cash margin receivable offset with derivatives	(36.6)	(135.4)
Netting of assets and liabilities with the same counterparty	(117.0)	(73.0)
Total	$ 116.2	$ 58.1
Derivative Instrument Assets, per Consolidated Balance Sheets:		
Current Assets: Other	$ 113.1	$ 57.0
Deferred Charges and Other Assets: Other	3.1	1.1
Total	$ 116.2	$ 58.1
Fair value of derivative liabilities presented above	$ 178.5	$ 164.7
Netting of assets and liabilities with the same counterparty	(117.0)	(73.0)
Total	$ 61.5	$ 91.7
Derivative Instrument Liabilities, per Consolidated Balance Sheets:		
Current Liabilities: Other	$ 51.1	$ 77.5
Deferred Credits and Other Liabilities: Other	10.4	14.2
Total	$ 61.5	$ 91.7

Additionally, at September 30, 2022 and 2021, the Company had $49.8 and $40.8, respectively, in cash margin receivables not offset with derivatives, which are presented in Accounts Receivable – Other.

Spire Missouri

Spire Missouri has a risk management policy to utilize various derivatives, including futures contracts, exchange-traded options, swaps and over-the-counter instruments for the explicit purpose of managing price risk associated with purchasing and delivering natural gas on a regular basis to customers in accordance with its tariffs. The objective of this policy is to limit Spire Missouri's exposure to natural gas price volatility and to manage, hedge and mitigate substantial price risk. This policy strictly prohibits speculation and permits Spire Missouri to hedge current physical natural gas purchase commitments or forecasted or anticipated future peak (maximum) physical need for natural gas delivered. Costs and cost reductions, including carrying costs, associated with Spire Missouri's use of natural gas derivative instruments are allowed to be passed on to Spire Missouri customers through the operation of its PGA clause, through which the MoPSC allows Spire Missouri to recover gas supply costs, subject to prudence review by the MoPSC. Accordingly, Spire Missouri does not expect any adverse earnings impact as a result of the use of these derivative instruments.

Spire Missouri does not designate these instruments as hedging instruments for financial reporting purposes because gains or losses associated with the use of these derivative instruments are deferred and recorded as regulatory assets or regulatory liabilities pursuant to ASC Topic 980, *Regulated Operations*, and, as a result, have no direct impact on the statements of income.

The timing of the operation of the PGA clause may cause interim variations in short-term cash flows, because Spire Missouri is subject to cash margin requirements associated with changes in the values of these instruments. Nevertheless, carrying costs associated with such requirements are recovered through the PGA clause.

From time to time, Spire Missouri purchases NYMEX futures and options contracts to help stabilize operating costs associated with forecasted purchases of gasoline and diesel fuels used to power vehicles and equipment used in the course of its business. These contracts are designated as cash flow hedges of forecasted transactions pursuant to ASC Topic 815, *Derivatives and Hedging*. The gains or losses on these derivative instruments are not subject to Spire Missouri's PGA clause. At September 30, 2022, Spire Missouri had no gasoline futures contracts outstanding.

Derivative instruments designated as cash flow hedges of forecasted transactions are recognized on the balance sheets at fair value and the change in the fair value of the effective portion of these hedge instruments is recorded, net of income tax, in OCI. AOCI is a component of Total Common Stock Equity. Amounts are reclassified from AOCI into earnings when the hedged items affect net income, using the same revenue or expense category that the hedged item impacts. As in both 2021 and 2020, there will be no reclassifications into the statements of income during fiscal 2023. Cash flows from hedging transactions are classified in the same category as the cash flows from the items that are being hedged in the statements of cash flows.

Spire Missouri's derivative instruments consist primarily of NYMEX positions. The NYMEX is the primary national commodities exchange on which natural gas derivatives are traded. Open NYMEX natural gas futures positions at September 30, 2022 and 2021 were as follows:

	September 30, 2022		September 30, 2021	
	Notional (MMBtu millions)	Maximum Term (Months)	Notional (MMBtu millions)	Maximum Term (Months)
Natural gas futures purchased	13.0	12	52.8	12

At September 30, 2022, Spire Missouri had also had 23.4 MMBtu of other price mitigation in place through the use of NYMEX natural gas option-based strategies.

Gains and losses on Spire Missouri's natural gas derivative instruments, which are not designated as hedging instruments for financial reporting purposes, are deferred pursuant to the Spire Missouri's PGA clauses and initially recorded as regulatory assets or regulatory liabilities. Such amounts are recognized in the statements of income as a component of natural gas operating expenses when they are recovered through the PGA clause and reflected in customer billings.

Fair Value of Derivative Instruments in the Balance Sheets

	Derivative Assets*		Derivative Liabilities*	
September 30, 2022	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
Derivatives not designated as hedging instruments				
Natural gas contracts	Current Assets: Other	$ 57.8	Current Liabilities: Other	$ 30.7
September 30, 2021				
Derivatives not designated as hedging instruments				
Natural gas contracts	Current Assets: Other	$ 104.0	Current Liabilities: Other	$ 0.3

* The fair values of Derivative Assets and Derivative Liabilities exclude the fair value of cash margin receivables or payables with counterparties subject to netting arrangements. Fair value amounts of derivative contracts (including the fair value amounts of cash margin receivables and payables) for which there is a legal right to set off are presented net on the Balance Sheets. As such, the gross balances presented in the table above are not indicative of Spire Missouri's net economic exposure. Refer to Note 9, Fair Value Measurements, for information on the valuation of derivative instruments.

Following is a reconciliation of the amounts in the tables above to the amounts presented in Spire Missouri's Balance Sheets:

	2022	2021
Fair value of derivative assets presented above	$ 57.8	$ 104.0
Fair value of cash margin (payable) receivable offset with derivatives	(27.1)	(103.7)
Netting of assets and liabilities with the same counterparty	(30.7)	(0.3)
Total	$ —	$ —
Fair value of derivative liabilities presented above	$ 30.7	$ 0.3
Netting of assets and liabilities with the same counterparty	(30.7)	(0.3)
Total	$ —	$ —

Additionally, at September 30, 2022 and 2021, Spire Missouri had $24.0 and $40.3, respectively, in cash margin receivables not offset with derivatives, which are presented in Accounts Receivable – Other.

Spire Alabama

Spire Alabama periodically employs a gasoline derivative program to help stabilize operating costs associated with forecasted purchases of gasoline and diesel fuels used to power vehicles and equipment used in the course of its business. The gains or losses on these derivative instruments are not subject to Spire Alabama's GSA rider. There were no such contracts outstanding as of September 30, 2022 and 2021.

11. CONCENTRATIONS OF CREDIT RISK

Spire's Gas Utility segment serves 1.7 million customers in three states across multiple rate classes resulting in a significant amount of revenue diversity. Credit risk is mitigated by the high percentage of residential customers as well as the geographic diversity of the Utilities, though customers for each of the Utilities are concentrated in a single state.

Spire Marketing's accounts receivable attributable to utility companies and their marketing affiliates totaled $245.6 at September 30, 2022. The concentration of transactions with these counterparties has the potential to affect the Company's overall exposure to credit risk, either positively or negatively, in that customers in this group may be affected similarly by changes in economic, industry, or other conditions. Spire Marketing also has concentrations of credit risk with certain individually significant counterparties. At September 30, 2022, the amounts included in accounts receivable from its five largest counterparties (in terms of net accounts receivable exposure) totaled $111.2. Four of these five counterparties are investment-grade rated integrated utilities, while the fifth is rated slightly below investment-grade, but with a stable outlook.

To manage these risks, Spire Marketing has established procedures to determine the creditworthiness of its counterparties. These procedures include obtaining credit ratings and credit reports, analyzing counterparty financial statements to assess financial condition, and considering the industry environment in which the counterparty operates. This information is monitored on an ongoing basis. In some instances, Spire Marketing may require credit assurances such as prepayments, letters of credit, or parental guaranties. In addition, Spire Marketing may enter into netting arrangements to mitigate credit risk with counterparties in the energy industry with whom it conducts both sales and purchases of natural gas. Where there is no netting arrangement, Spire Marketing records accounts receivable, accounts payable, and prepayments for physical sales and purchases of natural gas on a gross basis. Sales are typically made on an unsecured credit basis with payment due the month following delivery. Accounts receivable amounts are closely monitored and provisions for uncollectible amounts are accrued when losses are probable.

12. INCOME TAXES

The Company, Spire Missouri, and Spire Alabama are subject to federal income tax as well as income tax in various state and local jurisdictions. Spire files a consolidated federal income tax return and various state income tax returns and allocates income taxes to Spire Missouri, Spire Alabama and its other subsidiaries as if each entity were a separate taxpayer.

The provision for income taxes during the fiscal years ended September 30, 2022, 2021, and 2020 was as follows:

	Spire			Spire Missouri			Spire Alabama		
	2022	2021	2020	2022	2021	2020	2022	2021	2020
Federal:									
Current	$ 0.5	$ 0.2	$ 0.4	$ —	$ —	$ —	$ —	$ —	$ —
Deferred	47.0	49.5	5.8	18.2	22.0	14.9	18.1	19.8	17.4
Investment tax credits	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	—	—	—
State and local:									
Current	0.5	1.3	3.0	—	—	0.1	—	—	—
Deferred	11.1	17.7	3.4	3.3	3.5	2.5	5.1	5.2	4.6
Total income tax expense	$ 58.9	$ 68.5	$ 12.4	$ 21.3	$ 25.3	$ 17.3	$ 23.2	$ 25.0	$ 22.0

The effective income tax rate varied from the federal statutory income tax rate for each year due to the following:

	Spire			Spire Missouri			Spire Alabama		
	2022	2021	2020	2022	2021	2020	2022	2021	2020
Federal income tax statutory rate	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%
State and local income taxes, net of federal income tax benefits	3.6	3.6	9.0	2.6	2.6	2.6	4.1	4.1	4.1
Certain expenses capitalized on books and deducted on tax return	(1.6)	(1.6)	(6.6)	(3.2)	(3.3)	(4.6)	—	—	—
Taxes related to prior years	(0.3)	(0.5)	(1.8)	(0.6)	(0.2)	(1.4)	—	—	0.1
Amortization of excess deferred taxes	(3.5)	(2.5)	(8.3)	(7.3)	(5.0)	(5.7)	—	—	—
Other items – net *	1.9	0.1	(1.0)	3.1	(0.2)	(0.2)	0.2	0.2	(0.1)
Effective income tax rate	21.1%	20.1%	12.3%	15.6%	14.9%	11.7%	25.3%	25.3%	25.1%

* Other consists primarily of property adjustments.

The significant items comprising the net deferred tax liability or asset as of September 30 were as follows:

	Spire		Spire Missouri		Spire Alabama	
	2022	2021	2022	2021	2022	2021
Deferred tax assets:						
Reserves not currently deductible	$ 33.5	$ 18.3	$ 4.0	$ 8.5	$ 7.4	$ 6.6
Pension and other postretirement benefits	72.6	77.4	52.6	53.4	—	—
Goodwill	—	—	—	—	73.0	87.2
Operating losses	255.1	264.5	116.9	110.3	140.3	130.3
Regulatory amount due to customers, net	34.5	33.2	30.7	29.4	—	—
Other	24.9	32.4	—	—	—	—
Deferred tax assets	420.6	425.8	204.2	201.6	220.7	224.1
Less: Valuation allowance	—	(0.5)	—	(0.4)	—	—
Total deferred tax assets	420.6	425.3	204.2	201.2	220.7	224.1
Deferred tax liabilities:						
Relating to property	(740.0)	(693.9)	(489.3)	(464.0)	(201.6)	(182.7)
Regulatory pension and other postretirement benefits	(92.8)	(95.6)	(72.3)	(71.2)	(1.6)	(1.6)
Deferred gas costs	(75.8)	(81.1)	(74.0)	(79.5)	—	—
Other**	(187.1)	(167.0)	(68.7)	(66.5)	(6.5)	(5.6)
Total deferred tax liabilities	(1,095.7)	(1,037.6)	(704.3)	(681.2)	(209.7)	(189.9)
Net deferred tax (liability) asset	$ (675.1)	$ (612.3)	$ (500.1)	$ (480.0)	$ 11.0	$ 34.2

** For Spire, Other consists primarily of goodwill-related liabilities.

As indicated in Note 1, Summary of Significant Accounting Policies, the Company's regulated operations accounting for income taxes is impacted by ASC Topic 980, *Regulated Operations*. The Tax Cuts and Jobs Act of 2017 (TCJA) reduced the corporate federal income tax rate, and the corresponding reductions in deferred income tax balances resulted in amounts previously collected from utility customers for these deferred taxes becoming refundable to such customers, generally through reductions in future rates. The TCJA includes provisions that stipulate how these excess deferred taxes are to be passed back to customers for certain accelerated tax depreciation benefits. In fiscal 2018, the MoPSC Amended Report and Order took effect and the estimated excess accumulated deferred income tax began to be returned to Spire Missouri customers in rates. During the current fiscal year, the amount of excess accumulated deferred income taxes was trued up as part of the rate proceeding. The amount being returned related to the TCJA has been updated and in addition the excess accumulated deferred income taxes related to the Missouri tax rate change has begun to be returned. Excess accumulated deferred taxes of $9.9 were returned in fiscal 2022 and $8.4 were returned by Spire Missouri during each of fiscal years 2021, and 2020. The treatment for accumulated deferred income tax balances for Spire Alabama, Spire Gulf and Spire Mississippi is yet to be determined by state regulators; however, discussions have begun with respect to these balances.

In assessing whether deferred tax assets are realizable, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. Management considers all significant available positive and negative evidence, including the existence of losses in recent years, the timing of deferred tax liability reversals, projected future taxable income, taxable income in carryback years, and tax planning strategies to assess the need for a valuation allowance. Based upon this evidence, management believes it is more likely than not the Company, Spire Missouri and Spire Alabama will realize the benefits of these deferred tax assets.

As of September 30, 2022, Spire, and on a separate company basis, Spire Missouri and Spire Alabama, had federal and state loss carryforwards, contribution carryforwards, and various tax credit carryforwards as shown below.

	Spire	Spire Missouri	Spire Alabama
Federal and state loss carryforwards	$ 1,047.7	$ 462.3	$ 556.7
Contribution carryforwards	10.4	7.0	0.4
Tax credit carryforwards	4.6	3.4	—

For federal tax purposes, Spire Missouri's and Spire Alabama's loss carryforwards may be utilized against income from another member of the consolidated group. The loss carryforwards begin to expire in fiscal 2030 for certain state purposes and fiscal 2035 for federal and other state purposes. Contribution carryforwards and tax credit carryforwards are expected to be utilized prior to their expiration.

The Company, Spire Missouri and Spire Alabama recognize the tax benefit from a tax position only if it is at least more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. Unrecognized tax benefits are reported as a reduction of a deferred tax asset for an operating loss carryforward to the extent the recognition of the benefit would impact the operating loss carryforward, pursuant to ASU 2013-11. The following table presents a reconciliation of the beginning and ending balances of unrecognized tax benefits:

	Spire			Spire Missouri		
	2022	2021	2020	2022	2021	2020
Unrecognized tax benefits, beginning of year	$ 16.4	$ 13.2	$ 10.7	$ 16.1	$ 13.0	$ 10.4
Increases related to tax positions taken in current year	3.3	3.2	2.6	3.2	3.1	2.6
Reductions due to lapse of applicable statute of limitations	(0.1)	—	(0.1)	—	—	—
Unrecognized tax benefits, end of year	$ 19.6	$ 16.4	$ 13.2	$ 19.3	$ 16.1	$ 13.0

As of September 30, 2022 and 2021, the amounts of unrecognized tax benefits which, if recognized, would affect the effective tax rate were $4.0 and $3.6, respectively, for the Company and $3.7 and $3.3, respectively, for Spire Missouri. It is reasonably possible that events will occur in the next 12 months that could increase or decrease the amount of the unrecognized tax benefits. The Company and Spire Missouri do not expect that any such change will be significant to the balance sheets. Spire Alabama reported no unrecognized tax benefits for fiscal years 2022, 2021, and 2020.

The Company, Spire Missouri, and Spire Alabama record potential interest and penalties related to uncertain tax positions as interest expense and other income deductions, respectively. As of September 30, 2022 and 2021, interest accrued associated with uncertain tax positions was de minimis, and no penalties were accrued.

The Company, Spire Missouri, and Spire Alabama are no longer subject to examination for fiscal years prior to 2019, except to the extent the net operating losses from prior years are reviewed.

13. PENSION PLANS AND OTHER POSTRETIREMENT BENEFITS

Pension Plans

The pension plans of Spire consist of plans for employees at Spire Missouri, the employees of Spire Alabama and employees of the subsidiaries of Spire EnergySouth.

Spire Missouri and Spire Alabama have non-contributory, defined benefit, trusteed forms of pension plans covering the majority of their employees. Plan assets consist primarily of corporate and U.S. government obligations and a growth segment consisting of exposure to equity markets, commodities, real estate and international credit markets.

The net periodic pension cost includes components shown in the following table. The components other than the service costs and regulatory adjustment are presented in “Other Income, Net” in the income statement, except for Spire Alabama’s losses on lump-sum settlements. Such losses are capitalized in regulatory balances and amortized over the remaining actuarial life of individuals in the plan, and that amortization is presented in “Other Income, Net.”

	Spire			Spire Missouri			Spire Alabama		
	2022	2021	2020	2022	2021	2020	2022	2021	2020
Service cost – benefits earned during the period	$ 20.0	$ 21.7	$ 22.5	$ 14.4	$ 15.4	$ 15.7	$ 4.8	$ 5.5	$ 6.1
Interest cost on projected benefit obligation	21.5	20.7	22.6	14.7	14.2	15.8	4.7	4.6	4.9
Expected return on plan assets	(31.3)	(31.6)	(35.0)	(22.7)	(22.5)	(24.6)	(5.2)	(5.8)	(6.9)
Amortization of prior service (credit) cost	(4.5)	(3.1)	(2.5)	(1.9)	(0.6)	0.1	(2.4)	(2.3)	(2.4)
Amortization of actuarial loss	11.9	14.9	14.4	9.6	11.0	11.3	2.4	3.9	3.1
Loss on lump-sum settlements and curtailments	33.6	18.2	31.6	27.3	11.6	26.6	6.3	6.6	5.0
Subtotal	51.2	40.8	53.6	41.4	29.1	44.9	10.6	12.5	9.8
Regulatory adjustment	12.5	20.6	6.6	9.9	19.0	3.9	1.7	0.7	1.8
Net pension cost	$ 63.7	$ 61.4	$ 60.2	$ 51.3	$ 48.1	$ 48.8	$ 12.3	$ 13.2	$ 11.6

Other changes in plan assets and pension benefit obligations recognized in other comprehensive income or loss include the following:

	Spire			Spire Missouri			Spire Alabama		
	2022	2021	2020	2022	2021	2020	2022	2021	2020
Current year actuarial (gain) loss	$(16.9)	$ (8.1)	$ 68.0	$ 0.9	$ (0.9)	$ 37.8	$(16.0)	$ (1.5)	$ 24.4
Amortization of actuarial loss	(11.9)	(14.9)	(14.4)	(9.6)	(11.0)	(11.3)	(2.4)	(3.9)	(3.1)
Acceleration of loss recognized due to settlement	(33.6)	(18.2)	(31.7)	(27.3)	(11.6)	(26.6)	(6.3)	(6.6)	(5.1)
Current year service credit	—	(17.9)	(4.4)	—	(17.9)	(4.4)	—	—	—
Amortization of prior service credit (cost)	4.5	3.1	2.5	1.9	0.6	(0.1)	2.4	2.3	2.4
Subtotal	(57.9)	(56.0)	20.0	(34.1)	(40.8)	(4.6)	(22.3)	(9.7)	18.6
Regulatory adjustment	56.3	57.3	(19.5)	32.5	42.1	5.1	22.3	9.7	(18.6)
Total recognized in OCI	$ (1.6)	$ 1.3	$ 0.5	$ (1.6)	$ 1.3	$ 0.5	$ —	$ —	$ —

Spire pension obligations are driven by separate plan and regulatory provisions governing Spire Missouri, Spire Alabama and Spire EnergySouth pension plans.

Pursuant to the provisions of Spire Missouri’s and Spire Alabama’s pension plans, pension obligations may be satisfied by monthly annuities, lump-sum cash payments, or special termination benefits. Lump-sum payments are recognized as settlements (which can result in gains or losses) only if the total of such payments exceeds the sum of service and interest costs in a specific year. Special termination benefits, when offered, are also recognized as settlements which can result in gains or losses.

In the fiscal year ended September 30, 2022, two Spire Missouri plans and two Spire Alabama plans met the criteria for settlement recognition, requiring re-measurement of the obligation under those plans using updated census data and assumptions for discount rate and mortality. For the remeasurements, the discount rates for the Missouri plans were updated to 5.7% and 5.8%, respectfully, for each plan at September 30, 2022 (from 3.0%, respectfully, at September 30, 2021), and the discount rate for the Alabama plans were updated to 5.70% and 5.65%, respectfully, (from 3.1% and 3.0%, respectfully). Lump-sum payments recognized as settlements during fiscal year 2022 was $109.3 ($87.0 attributable to Spire Missouri and $22.3 to Spire Alabama). The Alabama regulatory tariff requires that settlement losses be amortized over the remaining actuarial life of the individuals in the plan, and in fiscal 2022 the amortization periods range from 11.4 years to 12.3 years. Therefore, no lump sum settlement expenses were recorded in the fiscal year ended September 30, 2022.

In the fiscal year ended September 30, 2021, two Spire Missouri plans and one Spire Alabama plan met the criteria for settlement recognition, requiring re-measurement of the obligation under those plans using updated census data and assumptions for discount rate and mortality. For the remeasurements, the discount rates for the Missouri plans were updated to 3.00% at September 30, 2021 (from 2.85% at September 30, 2020), and the discount rate for the Alabama plan was updated to 3.10% (from 2.95%). Lump-sum payments recognized as settlements during fiscal year 2021 was $67.5 ($44.6 attributable to Spire Missouri and $22.9 to Spire Alabama). The Alabama regulatory tariff requires that settlement losses be amortized over the remaining actuarial life of the individuals in the plan, and in fiscal 2021 the amortization periods range from 11.4 years to 11.7 years. Therefore, no lump sum settlement expenses were recorded in the fiscal year ended September 30, 2021.

Effective December 23, 2021, the pension cost for Spire Missouri's western territory (Missouri West) included in customer rates was reduced from $5.5 to $4.4 per year, the pension cost included in Spire Missouri's eastern territory (Missouri East) customer rates was increased from $29.0 to $32.4 per year. The difference between these amounts and pension expense as calculated pursuant to the above and that otherwise would be included in the statements of income and statements of comprehensive income is deferred as a regulatory asset or regulatory liability.

Also effective December 23, 2021, Missouri East prepaid pension assets and other postretirement benefits that were previously being included in rates at $21.6 per year for eight years were reduced to $11.0 per year, with the amortization period being reset for another eight years. Missouri West net liability for pension and other postretirement benefits that were previously reducing rates by $3.3 per year for eight years were reduced to a $1.1 reduction in rates per year, with the amortization period being reset for another eight years.

The following table shows the reconciliation of the beginning and ending balances of the pension benefit obligation at September 30:

	Spire		Spire Missouri		Spire Alabama	
	2022	2021	2022	2021	2022	2021
Benefit obligation, beginning of year	$ 689.6	$ 732.6	$ 479.0	$ 505.2	$ 149.4	$ 163.5
Service cost	20.0	21.7	14.4	15.4	4.8	5.5
Interest cost	21.5	20.7	14.7	14.2	4.7	4.6
Actuarial (gain) loss	(173.9)	6.6	(116.2)	11.0	(42.4)	(1.8)
Plan amendments	—	(17.9)	—	(17.9)	—	—
Settlement loss	33.4	12.3	27.9	8.2	5.6	4.1
Settlement benefits paid	(109.3)	(67.6)	(87.0)	(44.6)	(22.3)	(22.9)
Regular benefits paid	(16.9)	(18.8)	(12.2)	(12.5)	(2.0)	(3.6)
Benefit obligation, end of year	$ 464.4	$ 689.6	$ 320.6	$ 479.0	$ 97.8	$ 149.4
Accumulated benefit obligation, end of year	$ 457.1	$ 673.3	$ 315.0	$ 465.4	$ 96.2	$ 146.9

In 2022, all qualified plans experienced significant actuarial gains. These gains were driven by the discount rates increasing between 2.55% and 2.80% compared to the prior fiscal year, combined with lump sum rates that increased significantly since the prior fiscal year, which decreased the liability and contributed to liability gains. These gains were only partly offset by the losses on actual lump sum benefit payments compared to assumed amounts across all the plans. Actuarial losses 2021 were primarily due to the decrease in lump sum discount rates in one Spire Missouri plan and the losses on actual lump sum benefit payments compared to assumed amounts across all the plans. Except for Spire Alabama in 2021, these losses more than offset the gains that resulted from the increase in discount rates used to calculate the benefit obligations for each year.

The following table sets forth the reconciliation of the beginning and ending balances of the fair value of plan assets at September 30:

	Spire		Spire Missouri		Spire Alabama	
	2022	2021	2022	2021	2022	2021
Fair value of plan assets, beginning of year	$ 498.9	$ 473.1	$ 364.0	$ 336.2	$ 82.8	$ 88.6
Actual return on plan assets	(92.5)	58.8	(66.7)	42.7	(15.6)	9.6
Employer contributions	52.4	53.4	37.8	42.2	14.4	11.1
Settlement benefits paid	(109.3)	(67.6)	(87.0)	(44.6)	(22.3)	(22.9)
Regular benefits paid	(16.8)	(18.8)	(12.2)	(12.5)	(2.0)	(3.6)
Fair value of plan assets, end of year	$ 332.7	$ 498.9	$ 235.9	$ 364.0	$ 57.3	$ 82.8
Funded status of plans, end of year	$ (131.7)	$ (190.7)	$ (84.7)	$ (115.0)	$ (40.5)	$ (66.6)

The following table sets forth the amounts recognized in the balance sheets at September 30:

	Spire		Spire Missouri		Spire Alabama	
	2022	2021	2022	2021	2022	2021
Current liabilities	$ (1.1)	$ (0.8)	$ (1.1)	$ (0.8)	$ —	$ —
Noncurrent liabilities	(130.6)	(189.9)	(83.6)	(114.2)	(40.5)	(66.6)
Total	$ (131.7)	$ (190.7)	$ (84.7)	$ (115.0)	$ (40.5)	$ (66.6)

Pre-tax amounts recognized in accumulated other comprehensive loss not yet recognized as components of net periodic pension cost consist of:

	Spire		Spire Missouri		Spire Alabama	
	2022	2021	2022	2021	2022	2021
Net actuarial loss	$ 132.0	$ 194.6	$ 93.6	$ 129.6	$ 41.2	$ 66.1
Prior service credit	(35.7)	(40.3)	(18.1)	(20.1)	(16.3)	(18.7)
Subtotal	96.3	154.3	75.5	109.5	24.9	47.4
Adjustments for amounts included in regulatory assets	(93.1)	(149.5)	(72.3)	(104.7)	(24.9)	(47.4)
Total	$ 3.2	$ 4.8	$ 3.2	$ 4.8	$ —	$ —

The assumptions used to calculate net periodic pension costs for Spire Missouri are as follows:

	2022	2021	2020
Weighted average discount rate - Spire Missouri East plan	3.00%	2.85%	3.20%
Weighted average discount rate - Spire Missouri West plan	3.00%	2.75%	3.15%
Weighted average rate of future compensation increase	3.00%	3.00%	3.00%
Expected long-term rate of return on plan assets	6.75%	6.75%	7.25%

The assumptions used to calculate net periodic pension costs for Spire Alabama are as follows:

	2022	2021	2020
Weighted average discount rate	3.10%/3.0%	2.95%/2.80%	3.25%/3.20%
Weighted average rate of future compensation increase	3.00%	3.00%	3.00%
Expected long-term rate of return on plan assets	6.75%	6.75%	7.25%

The discount rate is based on long-term, high quality bond indices at the measurement date. The expected long-term rate of return on plan assets is based on historical and projected rates of return for current and planned asset classes in the investment portfolio. Assumed projected rates of return for each asset class were selected after analyzing historical experience and future expectations of the returns. The overall expected rate of return for the portfolio was developed based on the target allocation for each class.

The assumptions used to calculate the benefit obligations are as follows:

	2022	2021
Weighted average discount rate - Spire Missouri East plan	5.70%	3.00%
Weighted average discount rate - Spire Missouri West plan	5.80%	3.00%
Weighted average discount rate - Spire Alabama plans	5.70%/5.65%	3.1%/3.0%
Weighted average rate of future compensation increase	3.00%	3.00%
Cash balance interest crediting rate - Spire Alabama / Spire Missouri	4.25%	4.25%

The following table sets forth the year-end projected benefit obligation, accumulated benefit obligation, and fair value of plan assets for plans that have a projected benefit obligation and an accumulated benefit obligation in excess of plan assets:

	Spire		Spire Missouri		Spire Alabama	
	2022	2021	2022	2021	2022	2021
Projected benefit obligation	$ 464.4	$ 689.6	$ 320.6	$ 479.0	$ 97.8	$ 149.4
Accumulated benefit obligation	457.1	673.3	315.0	465.4	96.2	146.9
Fair value of plan assets	332.7	498.9	235.9	364.0	57.3	82.8

The following tables set forth the targeted and actual plan assets by category as of September 30 of each year for Spire Missouri and Spire Alabama:

Spire Missouri	2022 Target	2022 Actual	2021 Target	2021 Actual
Return seeking assets	70.0%	74.3%	70.0%	74.5%
Liability hedging assets	30.0%	22.8%	30.0%	23.1%
Cash and cash equivalents	—%	2.9%	—%	2.4%
Total	100.0%	100.0%	100.0%	100.0%

Spire Alabama	2022 Target	2022 Actual	2021 Target	2021 Actual
Return seeking assets	70.0%	68.7%	70.0%	72.8%
Liability hedging assets	30.0%	25.3%	30.0%	25.5%
Cash and cash equivalents	—%	6.0%	—%	1.7%
Total	100.0%	100.0%	100.0%	100.0%

The Spire Inc. Retirement Plans Committee is responsible for the administration of the various plans, and all payments under the plans require direction of that committee. The Spire Inc. Defined Benefit Plan Investment Review Committee utilizes an Outsourced Chief Investment Officer (OCIO) model where investment decisions are outsourced to investment consultants (Willis Towers Watson), who in turn become co-fiduciaries with the committee.

For all plans, the Company employs a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return of plan assets with a prudent level of risk. Risk tolerance is established through consideration of plan liabilities, plan funded status, corporate financial condition and market conditions. The Company has developed an investment strategy that focuses on asset allocation, diversification and quality guidelines. The investment goals are to obtain an adequate level of return to meet future obligations of the plan by providing above average risk-adjusted returns with a risk exposure in the mid-range of comparable funds. Comparative market and peer group benchmarks are utilized to ensure that investment managers are performing satisfactorily. The Company seeks to maintain an appropriate level of diversification to minimize the risk of large losses in a single asset class. Accordingly, plan assets for the pension plans do not have a concentration of assets in a single entity, industry, country, commodity or class of investment fund.

The following table sets forth expected pension benefit payments for the succeeding five fiscal years, and in aggregate for the five fiscal years thereafter, for Spire, Spire Missouri, and Spire Alabama:

	2023	2024	2025	2026	2027	2028- 2032
Spire	$ 55.8	$ 52.3	$ 47.2	$ 44.0	$ 43.5	$ 202.9
Spire Missouri	41.4	38.9	33.9	30.8	29.6	137.5
Spire Alabama	11.3	10.2	9.9	9.7	10.4	46.4

The funding policy of Spire Missouri and Spire Alabama is to contribute an amount not less than the minimum required by government funding standards nor more than the maximum deductible amount for federal income tax purposes. Spire Missouri's contributions to the pension plans in fiscal 2023 are anticipated to be $44.5 into the qualified trusts, and $1.1 into the non-qualified plans. Spire Alabama's contributions to the pension plans in fiscal 2023 are anticipated to be $13.8 into the qualified trusts.

Other Postretirement Benefits

Spire and the Utilities provide certain life insurance benefits at retirement. Spire Missouri plans provide for medical insurance after early retirement until age 65. For retirements prior to January 1, 2015, the Missouri West plans provided medical insurance after retirement until death. The Spire Alabama plans provide medical insurance upon retirement until death for certain retirees depending on the type of employee and the date the employee was originally hired.

Net periodic postretirement benefit costs consist of the following components:

	Spire			Spire Missouri			Spire Alabama		
	2022	2021	2020	2022	2021	2020	2022	2021	2020
Service cost – benefits earned during the period	$ 7.5	$ 7.3	$ 5.9	$ 6.3	$ 6.2	$ 5.3	$ 1.1	$ 0.9	$ 0.4
Interest cost on accumulated postretirement benefit obligation	6.0	6.0	6.3	4.5	4.5	4.7	1.4	1.3	1.4
Expected return on plan assets	(16.8)	(16.1)	(16.7)	(11.3)	(10.9)	(11.4)	(5.2)	(4.9)	(5.0)
Amortization of prior service cost (credit)	1.0	1.0	(0.5)	0.7	0.7	(0.2)	0.3	0.3	(0.3)
Amortization of actuarial gain	(2.2)	(1.6)	(2.0)	(1.9)	(1.5)	(2.0)	—	—	—
Subtotal	(4.5)	(3.4)	(7.0)	(1.7)	(1.0)	(3.6)	(2.4)	(2.4)	(3.5)
Regulatory adjustment	3.3	13.2	16.0	5.0	15.0	17.7	(1.8)	(1.8)	(1.8)
Net postretirement benefit (income) cost	$ (1.2)	$ 9.8	$ 9.0	$ 3.3	$ 14.0	$ 14.1	$ (4.2)	$ (4.2)	$ (5.3)

Other changes in plan assets and postretirement benefit obligations recognized in OCI include the following:

	Spire			Spire Missouri			Spire Alabama		
	2022	2021	2020	2022	2021	2020	2022	2021	2020
Current year actuarial loss (gain)	$ 15.8	$(41.0)	$ (7.3)	$ 9.8	$(29.0)	$ (7.6)	$ 5.9	$ (9.9)	$ 1.1
Amortization of actuarial gain	2.2	1.6	2.0	1.9	1.5	2.0	—	—	—
Current year prior service (cost) credit	(6.3)	—	15.8	(1.1)	—	9.5	(5.2)	—	6.3
Amortization of prior service (cost) credit	(1.0)	(1.0)	0.5	(0.7)	(0.7)	0.2	(0.3)	(0.3)	0.3
Subtotal	10.7	(40.4)	11.0	9.9	(28.2)	4.1	0.4	(10.2)	7.7
Regulatory adjustment	(10.7)	40.4	(11.0)	(9.9)	28.2	(4.1)	(0.4)	10.2	(7.7)
Total recognized in OCI	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

Pursuant to a MoPSC Order, the return on plan assets is based on the market-related value of plan assets implemented prospectively over a four-year period. Gains and losses not yet includible in postretirement benefit cost are amortized only to the extent that such gain or loss exceeds 10% of the greater of the accumulated postretirement benefit obligation or the market-related value of plan assets. Such excess is amortized over the average remaining service life of active participants. Effective April 18, 2018, the recovery in rates for Spire Missouri's postretirement benefit plans is based on an annual allowance of $8.6. The difference between these amounts and postretirement benefit cost based on the above and that otherwise would be included in the statements of income and statements of comprehensive income is deferred as a regulatory asset or regulatory liability.

The following table sets forth the reconciliation of the beginning and ending balances of the postretirement benefit obligation at September 30:

	Spire		Spire Missouri		Spire Alabama	
	2022	2021	2022	2021	2022	2021
Benefit obligation, beginning of year	$ 204.2	$ 212.3	$ 151.7	$ 158.4	$ 48.0	$ 48.3
Service cost	7.5	7.3	6.3	6.2	1.1	0.9
Interest cost	6.0	6.0	4.5	4.5	1.4	1.3
Actuarial (gain) loss	(52.6)	(7.5)	(37.7)	(6.7)	(13.6)	0.7
Plan amendments	(6.2)	—	(1.0)	—	(5.2)	—
Retiree drug subsidy program	0.2	—	0.2	—	—	—
Benefits paid	(11.0)	(13.9)	(9.2)	(10.7)	(1.8)	(3.2)
Benefit obligation, end of year	$ 148.1	$ 204.2	$ 114.8	$ 151.7	$ 29.9	$ 48.0

In fiscal 2022, the actuarial gains for all qualified Spire plans were driven by the increase in the discount rate used to calculate the benefit obligation. In fiscal 2021, the actuarial gains for Spire and Spire Missouri were driven by the increase in the discount rate used to calculate the benefit obligation. For Spire Alabama, this gain was more than offset by the loss associated with an update to the trend assumption.

The following table sets forth the reconciliation of the beginning and ending balances of the fair value of plan assets at September 30:

	Spire		Spire Missouri		Spire Alabama	
	2022	2021	2022	2021	2022	2021
Fair value of plan assets at beginning of year	$ 326.9	$ 291.0	$ 221.7	$ 199.2	$ 99.4	$ 87.0
Actual return on plan assets	(51.6)	49.7	(36.2)	33.1	(14.3)	15.6
Employer contributions	0.4	0.1	0.4	0.1	—	—
Benefits paid	(11.0)	(13.9)	(9.2)	(10.7)	(1.8)	(3.2)
Fair value of plan assets, end of year	$ 264.7	$ 326.9	$ 176.7	$ 221.7	$ 83.3	$ 99.4
Funded status of plans, end of year	$ 116.6	$ 122.7	$ 61.9	$ 70.0	$ 53.4	$ 51.4

The following table sets forth the amounts recognized in the balance sheets at September 30:

	Spire		Spire Missouri		Spire Alabama	
	2022	2021	2022	2021	2022	2021
Noncurrent assets	$ 151.6	$ 170.2	$ 96.9	$ 117.5	$ 53.4	$ 51.4
Current liabilities	(0.3)	(0.5)	(0.3)	(0.5)	—	—
Noncurrent liabilities	(34.7)	(47.0)	(34.7)	(47.0)	—	—
Total	$ 116.6	$ 122.7	$ 61.9	$ 70.0	$ 53.4	$ 51.4

Pre-tax amounts recognized in accumulated other comprehensive loss not yet recognized as components of net periodic postretirement benefit cost consist of:

	Spire		Spire Missouri		Spire Alabama	
	2022	2021	2022	2021	2022	2021
Net actuarial gain	$ (83.3)	$ (101.2)	$ (74.2)	$ (85.8)	$ (5.6)	$ (11.5)
Prior service cost (credit)	7.1	14.6	7.9	9.7	(0.8)	4.9
Subtotal	(76.2)	(86.6)	(66.3)	(76.1)	(6.4)	(6.6)
Adjustments for amounts included in regulatory assets	76.2	86.6	66.3	76.1	6.4	6.6
Total	$ —	$ —	$ —	$ —	$ —	$ —

The assumptions used to calculate net periodic postretirement benefit costs for Spire Missouri are as follows:

	2022	2021	2020
Weighted average discount rate - Spire Missouri plans	2.95%	2.75%	3.15%
Weighted average rate of future compensation increase	3.00%	3.00%	3.00%
Expected long-term rate of return on plan assets - Spire Missouri plans	5.75%	5.75%	6.25%

The assumptions used to calculate net periodic postretirement benefit costs for Spire Alabama are as follows:

	2022	2021	2020
Weighted average discount rate	2.95%	2.75%	3.15%
Expected long-term rate of return on plan assets	5.00%/6.25%	5.00%/6.25%	5.00%/6.25%

The discount rate is based on long-term, high quality bond indices at the measurement date. The expected long-term rate of return on plan assets is based on historical and projected rates of return for current and planned asset classes in the investment portfolio. Assumed projected rates of return for each asset class were selected after analyzing historical experience and future expectations of the returns. The overall expected rate of return for the portfolio was developed based on the target allocation for each class.

The assumptions used to calculate the accumulated postretirement benefit obligations are as follows:

	2022	2021
Weighted average discount rate - Spire Alabama plans	5.80%	2.95%
Weighted average discount rate - Spire Missouri plans	5.80%	2.95%
Weighted average rate of future compensation increase - Spire Missouri East plans	3.00%	3.00%

The assumed medical cost trend rates at September 30 are as follows:

	2022	2021
Medical cost trend assumed for next year - Spire Missouri	6.75%	7.00%
Medical cost trend assumed for next year - Spire Alabama	6.75%	7.00%
Rate to which the medical cost trend rate is assumed to decline (the ultimate medical cost trend rate)	5.00%	5.00%
Year the rate reaches the ultimate trend	2028	2028

The following tables set forth the targeted and actual plan assets by category as of September 30 of each year for Spire Missouri and Spire Alabama:

Spire Missouri	**Target**	**2022 Actual**	**2021 Actual**
Equity securities	60.0%	58.7%	59.2%
Debt securities	40.0%	40.5%	38.9%
Cash and cash equivalents	—%	0.8%	1.9%
Total	100.0%	100.0%	100.0%

Spire Alabama	**Target**	**2022 Actual**	**2021 Actual**
Equity securities	60.5%	57.7%	60.5%
Debt securities	39.5%	42.3%	39.5%
Total	100.0%	100.0%	100.0%

Missouri and Alabama state laws provide for the recovery in rates of costs accrued pursuant to GAAP provided that such costs are funded through an independent, external funding mechanism. The Utilities have established Voluntary Employees' Beneficiary Association and Rabbi Trusts as external funding mechanisms. Their investment policies seek to maximize investment returns consistent with their tolerance for risk. Outside investment management specialists are utilized in each asset class. Such specialists are provided with guidelines, where appropriate, designed to ensure that the investment portfolio is managed in accordance with policy. Performance and compliance with the guidelines is regularly monitored. Spire Missouri and Spire Alabama currently invest in mutual funds which are rebalanced periodically to the target allocation. The mutual funds are diversified across U.S. stock and bond markets, and for Spire Alabama, international stock markets.

The following table sets forth expected postretirement benefit payments for the succeeding five fiscal years, and in aggregate for the five fiscal years thereafter for Spire, Spire Missouri, and Spire Alabama:

	2023	2024	2025	2026	2027	2028 - 2032
Spire	$ 13.7	$ 14.4	$ 14.6	$ 14.5	$ 14.7	$ 69.5
Spire Missouri	11.6	12.2	12.3	12.2	12.2	55.7
Spire Alabama	1.9	2.0	2.1	2.1	2.2	11.9

The Utilities' funding policy is to contribute amounts to the trusts equal to the periodic benefit cost calculated pursuant to GAAP as recovered in rates. For both Spire Missouri and Spire Alabama there are no anticipated contributions to the postretirement plans in fiscal 2023.

Other Plans

Spire Services Inc. sponsors a 401(k) plan that cover substantially all employees of Spire Inc. and its subsidiaries. The plan allows employees to contribute a portion of their base pay in accordance with specific guidelines. The cost of the defined contribution plan for Spire Inc. totaled $15.5, $15.5, and $13.6 for fiscal years 2022, 2021, and 2020, respectively. Spire Missouri provides a match of such contributions within specific limits. The cost of the defined contribution plan for Spire Missouri amounted to $10.9, $10.9, and $9.5 for fiscal years 2022, 2021, and 2020, respectively. Spire Alabama also provides a match of employee contributions within specific limits. The cost of the defined contribution plan for Spire Alabama amounted to $3.6, $2.9, and $3.4 for fiscal years 2022, 2021, and 2020, respectively.

Fair Value Measurements of Pension and Other Postretirement Plan Assets

Spire

The table below categorizes the fair value measurements of the Spire pension plan assets:

	Quoted Prices in Active Markets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
As of September 30, 2022				
Cash and cash equivalents	$ 11.5	$ —	$ —	$ 11.5
Equity funds - global (including U.S.)	—	122.2	—	122.2
Real asset funds	—	61.0	—	61.0
Debt securities:				
U.S. bond funds	42.3	—	—	42.3
U.S. government index funds	36.1	—	—	36.1
Global funds (including U.S.)	—	59.6	—	59.6
Total	$ 89.9	$ 242.8	$ —	$ 332.7
As of September 30, 2021				
Cash and cash equivalents	$ 10.6	$ —	$ —	$ 10.6
Equity funds - global (including U.S.)	—	201.2	—	201.2
Real asset funds	—	87.7	—	87.7
Debt securities:				
U.S. bond funds	58.4	—	—	58.4
U.S. government index funds	60.1	—	—	60.1
Global funds (including U.S.)	—	80.9	—	80.9
Total	$ 129.1	$ 369.8	$ —	$ 498.9

The table below categorizes the fair value measurements of Spire's postretirement plan assets:

	Quoted Prices in Active Markets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
As of September 30, 2022				
Cash and cash equivalents	$ 3.5	$ —	$ —	$ 3.5
U.S. stock/bond mutual funds	177.1	69.4	—	246.5
International fund	0.8	13.9	—	14.7
Total	$ 181.4	$ 83.3	$ —	$ 264.7
As of September 30, 2021				
Cash and cash equivalents	$ 3.1	$ —	$ —	$ 3.1
U.S. stock/bond mutual funds	223.2	82.5	—	305.7
International fund	1.2	16.9	—	18.1
Total	$ 227.5	$ 99.4	$ —	$ 326.9

Cash and cash equivalents include money market mutual funds valued based on quoted market prices. Debt securities are valued based on broker/dealer quotations or by using observable market inputs. The stock and bond mutual funds are valued at the quoted market price of the identical securities.

Spire Missouri

The table below categorizes the fair value measurements of Spire Missouri's pension plan assets:

	Quoted Prices in Active Markets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
As of September 30, 2022				
Cash and cash equivalents	$ 5.7	$ —	$ —	$ 5.7
Equity funds - global (including U.S.)	—	85.7	—	85.7
Real asset funds	—	47.2	—	47.2
Debt securities:				
U.S. bond funds	29.4	—	—	29.4
U.S. government index funds	24.6	—	—	24.6
Global funds (including U.S.)	—	43.3	—	43.3
Total	$ 59.7	$ 176.2	$ —	$ 235.9
As of September 30, 2021				
Cash and cash equivalents	$ 8.3	$ —	$ —	$ 8.3
Equity funds - global (including U.S.)	—	148.6	—	148.6
Real asset funds	—	59.2	—	59.2
Debt securities:				
U.S. bond funds	38.4	—	—	38.4
U.S. government index funds	45.6	—	—	45.6
Global funds (including U.S.)	—	63.9	—	63.9
Total	$ 92.3	$ 271.7	$ —	$ 364.0

The table below categorizes the fair value measurements of Spire Missouri's postretirement plan assets:

	Quoted Prices in Active Markets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
As of September 30, 2022				
Cash and cash equivalents	$ 2.7	$ —	$ —	$ 2.7
U.S. stock/bond mutual funds	174.0	—	—	174.0
Total	$ 176.7	$ —	$ —	$ 176.7
As of September 30, 2021				
Cash and cash equivalents	$ 2.4	$ —	$ —	$ 2.4
U.S. stock/bond mutual funds	219.3	—	—	219.3
Total	$ 221.7	$ —	$ —	$ 221.7

Cash and cash equivalents include money market mutual funds valued based on quoted market prices. Debt securities are valued based on broker/dealer quotations or by using observable market inputs. The stock and bond mutual funds are valued at the quoted market price of the identical securities.

Spire Alabama

The table below categorizes the fair value measurements of Spire Alabama's pension plan assets:

	Quoted Prices in Active Markets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
As of September 30, 2022				
Cash and cash equivalents	$ 3.5	$ —	$ —	$ 3.5
Equity funds - global (including U.S.)	—	21.6	—	21.6
Real asset funds	—	8.1	—	8.1
Debt securities:				
U.S. bond funds	7.7	—	—	7.7
U.S. government index funds	6.8	—	—	6.8
Global funds (including U.S.)	—	9.6	—	9.6
Total	$ 18.0	$ 39.3	$ —	$ 57.3
As of September 30, 2021				
Cash and cash equivalents	$ 1.4	$ —	$ —	$ 1.4
Equity funds - global (including U.S.)	—	32.3	—	32.3
Real asset funds	—	14.6	—	14.6
Debt securities:				
U.S. bond funds	12.3	—	—	12.3
U.S. government index funds	8.9	—	—	8.9
Global funds (including U.S.)	—	13.3	—	13.3
Total	$ 22.6	$ 60.2	$ —	$ 82.8

The table below categorizes the fair value measurements of Spire Alabama's postretirement plan assets:

	Quoted Prices in Active Markets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
As of September 30, 2022				
U.S. stock/bond mutual funds	$ —	$ 69.4	$ —	$ 69.4
International fund	—	13.9	—	13.9
Total	$ —	$ 83.3	$ —	$ 83.3
As of September 30, 2021				
U.S. stock/bond mutual funds	$ —	$ 82.5	$ —	$ 82.5
International fund	—	16.9	—	16.9
Total	$ —	$ 99.4	$ —	$ 99.4

Cash and cash equivalents include money market mutual funds valued based on quoted market prices. Debt securities are valued based on broker/dealer quotations or by using observable market inputs. The stock and bond mutual funds are valued at the quoted market price of the identical securities.

14. INFORMATION BY OPERATING SEGMENT

The Company has two reportable segments: Gas Utility and Gas Marketing. The Gas Utility segment is the aggregation of the operations of the Utilities. The Gas Marketing segment includes the results of Spire Marketing, a subsidiary engaged in the non-regulated marketing of natural gas and related activities, including utilizing natural gas storage contracts for providing natural gas sales. Other components of the Company's consolidated information include:

- Spire STL Pipeline, a subsidiary of Spire providing interstate natural gas pipeline transportation services;
- Spire Storage, a subsidiary of Spire providing interstate natural gas storage services;
- Spire's subsidiaries engaged in the operation of a propane pipeline and risk management, among other activities; and
- unallocated corporate items, including certain debt and associated interest costs.

Accounting policies are described in Note 1, Summary of Significant Accounting Policies. Intersegment transactions include sales of natural gas from Spire Marketing to Spire Missouri and Spire Alabama, sales of natural gas from Spire Missouri to Spire Marketing, sales of natural gas from Spire Alabama to Spire Marketing, propane transportation services provided by Spire NGL Inc. to Spire Missouri, and propane storage services provided by Spire Missouri to Spire NGL Inc.

Management evaluates the performance of the operating segments based on the computation of net economic earnings. Net economic earnings exclude from reported net income the after-tax impacts of fair value accounting and timing adjustments associated with energy-related transactions, the impacts of acquisition, divestiture and restructuring activities, and the largely non-cash impacts of other non-recurring or unusual items such as certain regulatory, legislative or GAAP standard-setting actions.

2022	Gas Utility	Gas Marketing	Other	Eliminations	Consolidated
Revenues from external customers	$ 1,945.6	$ 234.9	$ 18.0	$ —	$ 2,198.5
Intersegment revenues	0.5	—	51.2	(51.7)	—
Total Operating Revenues	1,946.1	234.9	69.2	(51.7)	2,198.5
Operating Expenses					
Natural gas	788.8	171.4	—	(36.3)	923.9
Other operation and maintenance	413.3	14.6	37.1	(15.4)	449.6
Depreciation and amortization	227.9	1.4	8.0	—	237.3
Taxes, other than income taxes	176.2	0.6	2.7	—	179.5
Total Operating Expenses	1,606.2	188.0	47.8	(51.7)	1,790.3
Operating Income	$ 339.9	$ 46.9	$ 21.4	$ —	$ 408.2
Net Economic Earnings (Loss)	$ 202.7	$ 27.0	$ (13.4)	$ —	$ 216.3
Capital Expenditures	$ 528.6	$ 0.9	$ 22.7	$ —	$ 552.2

2021	Gas Utility	Gas Marketing	Other	Eliminations	Consolidated
Revenues from external customers	$ 2,118.2	$ 96.5	$ 20.8	$ —	$ 2,235.5
Intersegment revenues	1.1	—	46.9	(48.0)	—
Total Operating Revenues	2,119.3	96.5	67.7	(48.0)	2,235.5
Operating Expenses					
Natural gas	961.7	18.8	0.1	(34.3)	946.3
Other operation and maintenance	422.2	17.1	40.2	(13.7)	465.8
Depreciation and amortization	204.4	1.2	7.5	—	213.1
Taxes, other than income taxes	157.0	0.9	2.2	—	160.1
Impairments	—	—	—	—	—
Total Operating Expenses	1,745.3	38.0	50.0	(48.0)	1,785.3
Operating Income	$ 374.0	$ 58.5	$ 17.7	$ —	$ 450.2
Net Economic Earnings (Loss)	$ 230.6	$ 47.0	$ (11.3)	$ —	$ 266.3
Capital Expenditures	$ 590.4	$ 0.7	$ 33.7	$ —	$ 624.8

2020	Gas Utility	Gas Marketing	Other	Eliminations	Consolidated
Revenues from external customers	$ 1,751.8	$ 87.9	$ 15.7	$ —	$ 1,855.4
Intersegment revenues	0.2	—	42.1	(42.3)	—
Total Operating Revenues	1,752.0	87.9	57.8	(42.3)	1,855.4
Operating Expenses					
Natural gas	660.2	65.1	0.4	(29.6)	696.1
Other operation and maintenance	421.3	11.8	38.2	(12.7)	458.6
Depreciation and amortization	189.7	0.6	7.0	—	197.3
Taxes, other than income taxes	146.5	1.1	0.8	—	148.4
Impairments	—	—	148.6	—	148.6
Total Operating Expenses	1,417.7	78.6	195.0	(42.3)	1,649.0
Operating Income (Loss)	$ 334.3	$ 9.3	$ (137.2)	$ —	$ 206.4
Net Economic Earnings (Loss)	$ 213.4	$ 9.1	$ (14.7)	$ —	$ 207.8
Capital Expenditures	$ 547.8	$ 3.6	$ 87.0	$ —	$ 638.4

Total Assets at End of Year	**2022**	**2021**	**2020**
Gas Utility	$ 8,042.8	$ 7,615.4	$ 6,716.2
Gas Marketing	638.7	466.1	182.7
Other	2,895.2	2,351.7	2,443.5
Eliminations	(1,493.0)	(1,076.8)	(1,101.2)
Total Assets	$ 10,083.7	$ 9,356.4	$ 8,241.2

Reconciliation of Consolidated Net Income to Consolidated Net Economic Earnings	**2022**	**2021**	**2020**
Net Income	$ 220.8	$ 271.7	$ 88.6
Adjustments, pre-tax:			
Impairments	—	—	148.6
Missouri regulatory adjustments	—	(9.0)	—
Fair value and timing adjustments	(11.4)	3.3	2.5
Acquisition, divestiture and restructuring activities	—	(1.3)	—
Income tax effect of adjustments	6.9	1.6	(31.9)
Net Economic Earnings	$ 216.3	$ 266.3	$ 207.8

15. REGULATORY MATTERS

As discussed below for Spire Missouri and Spire Alabama, the Purchased Gas Adjustment (PGA) clauses and Gas Supply Adjustment (GSA) riders allow the Utilities to pass through to customers the cost of purchased gas supplies. Regulatory assets and regulatory liabilities related to the PGA clauses and the GSA rider are both labeled Unamortized Purchased Gas Adjustments herein.

The following regulatory assets and regulatory liabilities were reflected in the Balance Sheets as of September 30, 2022 and 2021.

	Spire		Spire Missouri		Spire Alabama	
September 30	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**
Regulatory Assets:						
Current:						
Pension and postretirement benefit costs	$ —	$ 31.1	$ —	$ 21.9	$ —	$ 8.2
Unamortized purchased gas adjustments	322.2	243.5	275.1	242.8	43.8	—
Other	33.2	31.9	13.0	11.6	13.1	10.6
Total Current Regulatory Assets	355.4	306.5	288.1	276.3	56.9	18.8
Noncurrent:						
Future income taxes due from customers	137.8	132.9	129.2	124.2	2.2	2.2
Pension and postretirement benefit costs	294.5	313.8	222.9	226.0	66.5	82.9
Cost of removal	493.7	431.9	25.2	34.9	468.5	397.0
Energy efficiency	57.2	47.6	57.2	47.6	—	—
Other	129.2	67.3	113.1	50.4	1.0	1.2
Total Noncurrent Regulatory Assets	1,112.4	993.5	547.6	483.1	538.2	483.3
Total Regulatory Assets	$ 1,467.8	$ 1,300.0	$ 835.7	$ 759.4	$ 595.1	$ 502.1
Regulatory Liabilities:						
Current:						
Pension and postretirement benefit costs	$ —	$ 5.8	$ —	$ 3.6	$ —	$ 2.2
Unamortized purchased gas adjustments	—	11.0	—	—	—	10.2
Other	3.7	17.8	—	13.5	—	1.0
Total Current Regulatory Liabilities	3.7	34.6	—	17.1	—	13.4
Noncurrent:						
Deferred taxes due to customers	145.3	127.5	127.9	110.2	—	—
Pension and postretirement benefit costs	172.6	159.3	143.6	131.4	19.4	19.8
Accrued cost of removal	32.9	36.2	—	4.9	—	—
Unamortized purchased gas adjustments	53.0	284.3	53.0	284.3	—	—
Other	14.4	13.6	7.3	8.0	3.6	3.6
Total Noncurrent Regulatory Liabilities	418.2	620.9	331.8	538.8	23.0	23.4
Total Regulatory Liabilities	$ 421.9	$ 655.5	$ 331.8	$ 555.9	$ 23.0	$ 36.8

A portion of the Company's regulatory assets are not earning a return and are shown in the schedule below:

	Spire		Spire Missouri	
September 30	**2022**	**2021**	**2022**	**2021**
Pension and postretirement benefit costs	$ 152.9	$ 165.7	$ 152.9	$ 165.7
Future income taxes due from customers	135.6	130.7	129.2	124.2
Unamortized purchase gas adjustments	275.1	242.8	275.1	242.8
Other	122.7	86.0	122.7	86.0
Total Regulatory Assets Not Earning a Return	$ 686.3	$ 625.2	$ 679.9	$ 618.7

Like all the Company's regulatory assets, these regulatory assets are expected to be recovered from customers in future rates. The recovery period for the future income taxes due from customers and pension and other postretirement benefit costs could be 20 years or longer, based on current Internal Revenue Service guidelines and average remaining service life of active participants, respectively. The recovery period for the PGA assets is normally about one year, but a portion will be three years due to the Filing Adjustment Factor discussed below. The other items not earning a return are expected to be recovered over a period not to exceed 15 years, consistent with precedent set by the MoPSC, except for certain debt costs expected to be recovered over the related debt term, up to 35 years. Spire Alabama does not have any regulatory assets that are not earning a return.

Spire Missouri

As authorized by the MoPSC, the PGA clause allows Spire Missouri to flow through to customers, subject to prudence review by the MoPSC, the cost of purchased gas supplies. To better match customer billings with market natural gas prices, Spire Missouri is allowed to file to modify, on a periodic basis, the level of gas costs in its PGA. Certain provisions of the PGA clause are included below:

- Spire Missouri has a risk management policy that allows for the purchase of natural gas derivative instruments with the goal of managing price risk associated with purchasing natural gas on behalf of its customers. The MoPSC clarified that costs, cost reductions, and carrying costs associated with the Utility's use of natural gas derivative instruments are gas costs recoverable through the PGA mechanism.
- The tariffs allow Spire Missouri flexibility to make up to three discretionary PGA changes during each year, in addition to its mandatory November PGA change, so long as such changes are separated by at least two months.
- Spire Missouri is authorized to apply carrying costs to all over- or under-recoveries of gas costs, including costs and cost reductions associated with the use of derivative instruments, including cash payments for margin deposits.
- Pre-tax income from off-system sales and capacity release revenues is shared with customers (such that customers receive 75% and Spire Missouri receives 25%), with an estimated amount assumed in PGA rates.

Pursuant to the provisions of the PGA clause, the difference between actual costs incurred and costs recovered through the application of the PGA clause, as well as the difference between the actual amount of off-system sales and capacity release revenues allocated to customers and the estimated amount assumed in PGA rates, are reflected as a regulatory asset or liability at the end of the fiscal year. At that time, the balance is classified as a current asset or current liability and recovered from, or credited to, customers over an annual period commencing in the subsequent November. The balance in the current account is amortized as amounts are reflected in customer billings.

On March 7, 2018, the MoPSC issued its order in two general rate cases (docketed as GR-2017-0215 and GR-2017-0216), approving new tariffs that became effective on April 19, 2018. Certain provisions of the order allowed less future recovery of certain deferred or capitalized costs than estimated based upon previous rate proceedings, and management determined that the related regulatory assets should be written down. Spire Missouri filed an appeal of portions of the MoPSC's order, including the disallowance of certain pension costs. On February 9, 2021, the Missouri Supreme Court issued its decision, reversing the MoPSC's order with respect to certain pension costs. The case was remanded back to the MoPSC with directions that $9.0 in pension assets that accrued between 1994 and 1996 be added to the Company's prepaid pension asset. Based on the court's decision, the Company increased its noncurrent regulatory asset for "Pension and postretirement benefit costs" and reduced operation and maintenance expense for the three months ended March 31, 2021. Like the original write-down in 2018, this adjustment is excluded for the net economic earnings financial measure. The remand issue is being considered as part of Spire Missouri's ongoing general rate case (discussed below).

The Infrastructure System Replacement Surcharge (ISRS) allows Spire Missouri expedited recovery for its investment to replace its worn out or deteriorated infrastructure without the necessity of a formal rate case. On November 19, 2019, the Missouri Western District Court of Appeals issued rulings ("ISRS rulings") that determined certain capital investments in 2016 through 2018 were not eligible for recovery under the ISRS. As a result, Spire Missouri recorded a $12.2 provision for fiscal year 2019, which was excluded for the net economic earnings financial measure. This matter was settled by the end of fiscal 2020. On December 23, 2021, Spire Missouri filed a new ISRS case, its first under the ISRS statute amendments of 2020, seeking accelerated recovery of $11.3 in annual revenue for eligible pipe replacement from June through December 2021. On April 21, 2022, the MoPSC approved a settlement among the parties to resolve the ISRS case, resulting in $8.5 in incremental annual revenue effective in May 2022. On June 3, 2022, Spire Missouri filed a new ISRS case, its first with the inclusion of the "Contractor Bid" requirement identified in the ISRS statute amendments of 2020, seeking accelerated recovery of $11.9 in annual revenue for eligible pipe replacement from January through June 2022. On October 5, 2022, the MoPSC approved a settlement among the parties to resolve the ISRS case, resulting in $10.5 in incremental revenue effective October 21, 2022, bringing total annual ISRS revenue to $19.0.

In September 2020, Spire Missouri, the MoPSC staff and the Office of Public Counsel (OPC) reached a Unanimous Stipulation and Agreement regarding Spire Missouri's request for an Accounting Authority Order (AAO) pertaining to certain costs and lost customer fee revenue related to the COVID-19 pandemic. In October 2020, the MoPSC issued an order approving that agreement and granting an AAO for the period of March 1, 2020 through March 31, 2021. As part of the 2021 rate order discussed below, the settled balance of deferred costs, including foregone late payment fees and reconnect/disconnect fees that Spire Missouri was authorized to defer, totaled $6.2 and will be recovered through a five-year amortization of a regulatory asset.

In mid-February 2021, the central U.S. experienced a period of unusually severe cold weather (“Winter Storm Uri”), and Spire Missouri implemented an Operational Flow Order (OFO) to preserve the integrity of its distribution system. During this time, Spire Missouri was required to purchase additional natural gas supply, both to ensure adequate supply for its firm utility customers, and to cover the shortfall created when third-party marketers failed to deliver natural gas supply to its city gates on behalf of their customers. In accordance with its tariffs, Spire Missouri invoiced the cost of gas and associated penalties totaling $195.8 to non-compliant marketers pursuant to the MoPSC-approved OFO tariff and recorded accounts receivable. Recoveries collected will be an offset to cost of natural gas for firm utility customers through the PGA and Actual Cost Adjustment (ACA), so are net income neutral to Spire Missouri. The three largest counterparties did not remit payment when due, so Spire Missouri filed suit against them in federal court to recover the invoiced amounts. Some marketers filed complaints with the MoPSC requesting review of the transactions between them and Spire Missouri. Through the first quarter of fiscal 2022, the Company had no reason to believe the MoPSC would not follow the tariff and had determined collection was probable, so the entire amount was recognized. In late February 2022, the parties to the OFO waiver suits agreed to a settlement in principle, pursuant to which marketers will reimburse Spire Missouri for the actual cost of its incremental gas purchases to serve marketers’ customers during Winter Storm Uri, so Spire Missouri reduced revenue, accounts receivable, cost of gas and regulatory liabilities by approximately $150 in the second quarter of fiscal 2022. The settlement, which reduced the total amount due from the three marketers to approximately $42, was approved by the MoPSC in late May 2022. Pursuant to the approved settlement, the marketers have begun making payments to Spire Missouri that will be credited to the PGA/ACA, the marketer complaints have been dismissed at the MoPSC, and Spire Missouri has dismissed its federal lawsuits against the marketers. Spire Missouri is not subject to any upstream OFO penalties on any interstate pipelines.

As a result of the significant net deferred gas costs and average inventory cost in the second quarter of fiscal 2021, primarily due to Winter Storm Uri, Spire Missouri filed for and received MoPSC approval for an adjustment to the PGA tariff to increase a Filing Adjustment Factor (FAF) credit on customers' bills for three years. This helps customers by lowering the net PGA rate to mitigate impacts from Winter Storm Uri costs and the increased gas market from 2020 to 2021. All gas costs will eventually be recovered by Spire Missouri through the PGA or ACA mechanisms and carrying costs will be applied per the terms of the tariff.

Spire Missouri is able to sell excess natural gas supply and capacity to third parties off-system, resulting in significant savings to its firm utility customers through the gas incentive mechanisms of its PGA as described above. Spire Missouri retains 25% and passes 75% through to its customers as gas cost savings. During Winter Storm Uri, Spire Missouri had an unusually large off-system sale resulting in $100.0 of incremental gross revenue. Due to the nature and magnitude of this particular transaction, Spire Missouri initially deferred recognition of its 25% share and established a regulatory liability to allow time to assess the transaction in light of the open rate proceeding. When the regulatory treatment became clear in the fourth quarter of fiscal 2021, the Company reversed the liability and recorded the amount in operating revenues.

The MoPSC approved compliance tariffs with an effective date of December 23, 2021, in Spire Missouri’s general rate case GR-2021-0108. These new tariffs were designed to increase Spire Missouri’s aggregate annual gross base rate revenues by $72.2, which includes $24.9 incremental and $47.3 already being collected through the Infrastructure System Replacement Surcharge (ISRS). The decision, as reflected in the amended report and order dated November 12, 2021, revised the MoPSC’s long-standing position regarding Spire Missouri’s compliance with the FERC Uniform System of Accounts (USOA) on the capitalization of prudently incurred non-operational overheads. The amended report and order required Spire Missouri to cease capitalization of these overhead costs at the time new rates went into effect until a MoPSC staff audit of their revised interpretation of compliance with the USOA framework could be completed. MoPSC staff completed this audit and filed its audit report on March 18, 2022. The report recommends changes to Spire Missouri’s overhead capitalization rates based upon its new time study and the results of the audit. On April 13, 2022, the MoPSC issued an Order Authorizing Accounting Treatment clarifying that Spire Missouri may defer all non-operational overheads from December 23, 2021 forward into a regulatory asset for future review by the MoPSC in an appropriate proceeding. Based on Spire Missouri’s assessment of recoverability, the total amount deferred under this order was $42.8 through September 30, 2022, comprising:

- $19.0 in accordance with new capitalization rates determined by the study and audit;
- $18.8 of prudent costs which are in excess of the capitalization rates determined by the study and audit; and
- $5.0 of prudent costs related to the April 2022 ISRS settlement discussed above.

On April 1, 2022, Spire Missouri filed tariff sheets to initiate a new general rate case proceeding which is intended to address the deferred amounts, along with other matters, and is expected to be resolved in the first half of fiscal 2023. The proposed tariff changes include revised rate schedules designed to produce an annual net increase in Spire Missouri's gas revenues of approximately $151.9. Intervenor direct testimony was filed in late August and early September 2022. The MoPSC has set a test year ending September 30, 2021, adjusted for known and measurable rate base, revenue and expense items through May 31, 2022, with a true-up period through September 30, 2022. On October 7, 2022, Spire Missouri and various intervenors filed rebuttal testimony. MoPSC staff also filed updated accounting schedules reflecting a revised revenue requirement of $71.0. Local public hearings concluded in mid-October 2022. Following these hearings, the parties reached a Full Unanimous Stipulation and Agreement (the "Stipulation") to resolve all issues in the case which was filed with the MoPSC on November 4, 2022. A hearing regarding this Stipulation is currently set for November 18, 2022. The remainder of the procedural schedule has been suspended, pending MoPSC action on the Stipulation. If approved, the Stipulation would, among other things, authorize $78.0 in new base rate revenue (with rates effective no later than January 1, 2023), and authorize recovery of deferred overheads through amortization of the related regulatory assets discussed in the previous paragraph.

On May 27, 2022, the MoPSC staff filed an ACA Review Recommendation and Report for the ACA period that first includes transportation charges incurred by Spire Missouri for service on the Spire STL Pipeline. That report concluded that the transaction complied with Missouri affiliate transaction rules and was prudent, and it recommended no disallowance of any Spire STL Pipeline related costs from the ACA mechanism. On July 11, 2022, Spire Missouri filed its response comments in support of the recommendation. The Missouri Office of the Public Counsel and Environmental Defense Fund filed comments on July 29 and August 1, 2022, respectively, raising concerns about the Spire STL Pipeline transaction, the ACA process itself, and other matters. The MoPSC has not yet taken any further action in the docket.

The MoPSC has initiated their annual ACA dockets (GR-2022-0135 and GR-2022-0136) to audit gas commodity and transportation costs for the 2020-2021 heating season, which includes the impact of Winter Storm Uri on Spire Missouri's natural gas portfolio. The cases are expected to focus on the cost and amount of incremental natural gas purchases for the storm period, as well as the subscription and use of transportation and natural gas storage assets during the period.

On February 23, 2022, the MoPSC issued an order approving Spire Missouri's request for $800.0 in new financing authority over three years, subject to certain customary conditions.

Spire Alabama

In October 2018, the APSC approved the renewal of its Rate Stabilization and Equalization (RSE) rate-setting process for Spire Alabama through September 30, 2022, limiting equity as a percent of total capitalization to a range of 56.5% to 55.5%. Under RSE, the APSC conducts quarterly reviews to determine whether Spire Alabama's return on average common equity (ROE) at the end of the rate year will be within the allowed range of return. Reductions in rates can be made quarterly to bring the projected ROE within the allowed range; increases, however, are allowed only once each rate year, effective December 1, and cannot exceed 4% of prior-year revenues. Spire Alabama's allowed range of ROE is 10.15% to 10.65% with an adjusting point of 10.4%. In September 2022, the APSC approved the renewal of RSE through September 30, 2025, with certain modifications to the current terms. Effective October 1, 2022, Spire Alabama's allowed range of return on average common equity is 9.50% to 9.90% with an adjusting point of 9.70%. Average Common Equity growth is limited to 6.00% each year. Spire Alabama retains the ability to receive a performance-based adjustment of +/- 10 basis points to the return on equity adjusting point, based upon the terms of the previously approved Accelerated Infrastructure Modernization (AIM) Program tariff. However, in September of 2022, Spire applied for and received approval to suspend the operation of the AIM performance-based adjustment for 2023. The quarterly reviews have been modified to occur only in March, June, and September. Spire Alabama retained the current equity limitation as a percent of total capitalization at 55.5% and adjustments to the Cost Control Measure (CCM) as noted below.

The inflation-based CCM established by the APSC, allows for annual changes in operation and maintenance ("O&M") expense per customer relative to an index range. The CCM will be calculated based upon O&M expense per customer and the O&M base year will be Spire Alabama's actual 2018 O&M expense with an adjustment to that base in 2019 of 2/3 of the 2018 CCM differential (amount below the CCM range in 2018) and an adjustment in 2020 of 1/3 of the 2018 CCM differential, with no adjustment to the base in 2021 and 2022. Spire Alabama's 2018 actual rate year O&M expense will be inflation-adjusted using a new index range based on the June CPI-U each rate year plus or minus 1.50%. If rate year O&M expense falls within the index range, no adjustment is required. If rate year O&M expense exceeds the index range, three-quarters of the difference is returned to customers through future rate adjustments. To the extent rate year O&M is less than the index range, Spire Alabama benefits by one-half of the difference through future rate adjustments. Effective October 1, 2022, the Base Year O&M expense will be computed by averaging the actual O&M expenses for 2020, 2021, and 2022. The Base CPI-U will be computed by averaging the August CPI-U for 2020, 2021, 2022. The Index will be computed by measuring the change from the Base CPI-U to the August CPI-U of the preceding completed fiscal year, less a factor of 1.50%. The index range will be computed by adjusting the index plus or minus 1.50%. If rate year O&M expense falls within the index range, no adjustment is required. If rate year O&M expense exceeds the index range, three-quarters of the difference is returned to customers through future rate adjustments. To the extent rate year O&M is less than the index range, Spire Alabama benefits by one-half of the difference through future rate adjustments. If a benefit is achieved, the Base Year and the Base CPI-U for the following year will each be reset to an average of the three preceding completed years. If a benefit is not achieved, the Base Year and Base CPI-U will not be updated. Certain items that fluctuate based on situations demonstrated to be beyond Spire Alabama's control may be excluded from the CCM calculation.

The RSE reduction for September 30, 2021, following the year end point of test was $2.2 to bring the expected rate of return on average common equity to within the allowed rate of return. The CCM benefit for rate year 2021 was $8.8. To mitigate the impact on ratepayers, Spire Alabama requested and received approval from the APSC to recover the 2021 CCM benefit over five years (with recognition of revenue only up to 24 months in advance of recovery). As a part of the annual update for RSE, on December 29, 2021, Spire Alabama filed an increase for rate year 2022 of $5.3. The 2021 RSE reduction of $2.2, the five-year recovery of the 2021 CCM benefit of $8.8 and the annual RSE increase of $5.3 were all effective on January 1, 2022. There was no RSE reduction in 2022 for the January 31, April 30, July 31 or September 30 quarterly points of test. Spire Alabama recorded a CCM benefit for rate year 2022 of $17.2. Similar to the rate year 2021 CCM benefit, Spire has requested and received approval to recover the rate year 2022 CCM benefit over five years. On October 26, 2022, Spire Alabama made its annual RSE rate filing with the APSC, presenting the utility's budget for the fiscal year ending September 30, 2023, including net income and a calculation of allowed ROE.

Spire Alabama's rate schedules for natural gas distribution charges contain a GSA rider which permits the pass-through to customers of changes in the cost of gas supply. Spire Alabama's tariff provides a temperature adjustment mechanism, also included in the GSA rider, which is designed to moderate the impact of departures from normal temperatures on Spire Alabama's earnings. The temperature adjustment applies primarily to residential, small commercial and small industrial customers. Other non-temperature weather-related conditions that may affect customer usage are not included in the temperature adjustment. There is also a mechanism under Spire Alabama's GSA rider allowing the utility to create value through off-system sales of excess natural gas supply and capacity and to retain 25% of the value created while giving 75% of the value to customers. As of April 2022, the first $1.6 of value from capacity release goes entirely to customers before Spire Alabama retains 25%. In the past year, Spire Alabama filed GSA rate increases effective December 1, 2021, April 1, 2022, August 1, 2022, and October 1, 2022, primarily attributable to higher natural gas prices.

The APSC approved an Enhanced Stability Reserve (ESR) in 1998, which was subsequently modified and expanded in 2010. As currently approved, the ESR provides deferred treatment and recovery for the following: (1) extraordinary O&M expenses related to environmental response costs; (2) extraordinary O&M expenses related to self-insurance costs that exceed $1.0 per occurrence; (3) extraordinary O&M expenses, other than environmental response costs and self-insurance costs, resulting from a single force majeure event or multiple force majeure events greater than $0.3 and $0.4, respectively, during a rate year; and (4) negative individual large commercial and industrial customer budget revenue variances that exceed $0.4 during a rate year. Charges to the ESR are subject to certain limitations which may disallow deferred treatment and which prescribe the timing of recovery. Subsequent to the nine-year period and subject to APSC authorization, Spire Alabama expects to be able to recover underfunded ESR balances over a five-year amortization period with an annual limitation of $0.7. Amounts in excess of this limitation are deferred for recovery in future years.

On July 12, 2022, the APSC approved Spire Alabama's application for an intercompany revolving credit agreement allowing Spire Alabama to borrow from Spire in a principal amount not to exceed $275.0 (up from the previously approved $200.0) at any time outstanding in combination with its bank line of credit, and to loan to Spire in a principal amount not to exceed $25.0 (unchanged) at any time outstanding. On September 13, 2022, the APSC approved an application for up to $175.0 of additional long-term debt financing for Spire Alabama (ultimately issued on October 13, 2022).

Spire

In addition to those discussed above for Spire Missouri and Spire Alabama, Spire is affected by the following regulatory matters.

Spire Gulf has similar rate regulation to Spire Alabama. Its RSE rate-setting mechanism was renewed in September 2021 for a four-year term through September 2025. The RSE allowed ROE range was 10.45% to 10.95% with an adjusting point of 10.70% in fiscal 2021, while the ROE range is 9.70% to 10.30% with an adjusting point of 9.95% for fiscal 2022 through fiscal 2025. On October 26, 2021, Spire Gulf made its annual RSE rate filing with the APSC based on its budget for fiscal 2022 and an allowed ROE of 9.95%. New rates designed to provide increased annual revenues of $1.0 became effective January 3, 2022. On October 26, 2022, Spire Gulf made its annual RSE filing for fiscal 2023 reflecting an increase to annual revenues of $3.5 that is pending review by the APSC. The CCM has similar evaluation and recovery provisions when expenses exceed or are under a band of +/- 1.50% around the CPI-U inflated O&M per customer expense level from the base year, excluding expenses for pensions and gas bad debt. The base year for the O&M index was 2017 for fiscal 2020 and 2021 and was 2021 for fiscal 2022. Since a CCM benefit was recorded in fiscal 2022, the base year O&M index for fiscal 2023 through fiscal 2025 will be the 2022 O&M level. Spire Gulf recorded a CCM benefit for rate year 2021 of $2.3 to revenues, resulting in a net income benefit of $1.6. A CCM benefit of $1.7 was recorded for fiscal 2022 to an economic development fund that can be used for economic development purposes subject to APSC approval. Spire Gulf has a Cast Iron Main Replacement Factor (CIF) that provides an enhanced return on the pro-rata costs associated with cast iron main replacement exceeding 10 miles per year based on a 75% weighting for the equity content. Capital expenditures recovered under the CIF have not increased since fiscal 2019 pursuant to applicable tariff provisions although the Company is continuing to recover costs of service associated with accumulated expenditures under the CIF. Spire Gulf also has an ESR for negative revenue variances over $0.1 or a force majeure event expense of $0.1 (or two events that exceed $0.15), a Self Insurance Reserve for general liability coverage, and an Environmental Cost Recovery Factor that recovers 90% of prudently incurred costs for compliance with environmental laws, rules and regulations. Spire Gulf has an APSC-approved intercompany revolving credit agreement with Spire to borrow in a principal amount not to exceed $75.0 and to loan up to $25.0. On September 13, 2022, the APSC approved the issuance of $30.0 of long-term debt (ultimately issued on October 13, 2022) to refinance outstanding short-term debt.

Spire Mississippi utilizes a formula rate-making process under the Rate Stabilization Adjustment Rider (RSA). An allowed return on equity (currently 10.03%) is computed annually and compared to the actual return on equity based on a rate year ending June 30. If the actual equity return on an end of period rate base is beyond the allowed return on equity by 1.0%, then 75% of any shortfall is recovered through a rate increase and 50% of any excess results in a rate decrease. Updates may include known and measurable adjustments to historic costs from the 12 months ended June 30, submitted September 15 for an effective date of November 1, unless disputed by the Mississippi Public Utilities Staff (MPUS), with any disputes to be resolved by the Mississippi Public Service Commission (MSPSC) by January 15 of the following year. On January 12, 2021, the MSPSC approved an agreement between Spire Mississippi and the MPUS settling its RSA filing that was made on August 28, 2020, resulting in a $0.3 increase in annual revenue. New rates became effective January 13, 2021. On August 23, 2021, Spire Mississippi filed its RSA for the rate year ended June 30, 2021, which reflected an increase to annual revenue totaling $1.1. The MSPSC, by its order dated January 18, 2022, approved a stipulation agreement between the MPUS and Spire Mississippi that provided for increased annual revenues of $0.8 through rates that became effective on February 1, 2022. Spire Mississippi's RSA filing made on September 14, 2022 reflected a rate increase of $1.3 and is pending review by the MPUS. A Supplemental Growth Rider provides recovery of certain system expansion projects to serve qualified economic development projects.

In August 2018, the FERC approved an order issuing a Certificate of Public Convenience and Necessity for the Spire STL Pipeline (“August 2018 Order”). In November 2018, the FERC issued a Notice to Proceed, and in November 2019, Spire STL Pipeline received FERC authorization to place the pipeline into service. Also, in November 2019, the FERC issued an Order on Rehearing of the August 2018 Order dismissing or denying the outstanding requests for rehearing filed by several parties, dismissing the request for stay filed by one party, and noting the withdrawal of the request for rehearing by another party. In January 2020, two of the rehearing parties filed petitions for review of the FERC’s orders with the U.S. Court of Appeals for the District of Columbia Circuit (“DC Circuit”). On June 22, 2021, that court issued an order vacating the Certificate of Public Convenience and Necessity and remanding the matter back to the FERC for further action. On September 14, 2021, and December 3, 2021, the FERC issued temporary certificates to allow the pipeline to continue operating indefinitely while it considers approval of a new permanent certificate. Certain parties in the temporary certificate proceeding sought rehearing of the FERC’s December 3, 2021 temporary certificate. The FERC denied rehearing by operation of law on February 3, 2022. On March 7, 2022, one group of the rehearing parties filed a petition for review of FERC’s December 3, 2021 temporary certificate order in the DC Circuit limited to whether the temporary certificates carry eminent domain authority. On June 29, 2022, the DC Circuit issued an order holding the proceeding in abeyance pending the outcome of the FERC remand proceeding. Meanwhile on December 15, 2021, the FERC issued a notice of intent to prepare a supplemental environmental impact statement (EIS) regarding the Spire STL Pipeline. On October 7, 2022, the FERC staff issued its final EIS, concluding that “impacts from the continued operation of the Spire STL [Pipeline] would be less than significant, with the exception of climate change impacts resulting from GHG [greenhouse gas] emissions that are not characterized as significant or insignificant.”

Spire STL Pipeline will continue to pursue all legal and regulatory avenues to ensure access to reliable, affordable and safe delivery of energy for eastern Missouri. While there is no impairment at this time, if the pipeline is taken out of service, the Company’s financial condition and results of operations may be adversely impacted by impairment of Spire STL Pipeline’s assets, currently carried at over $270, and other effects. If Spire Missouri is unable to obtain sufficient pipeline capacity to meet its customers’ annual and seasonal natural gas demands, Spire Missouri’s financial condition and results of operations may be adversely impacted.

On October 9, 2020, Spire Storage West LLC (“Spire Storage”) filed with the FERC an Abbreviated Application for an Amendment of Certificate of Public Convenience and Necessity, Reaffirmation of Market-Based Rate Authority, and Related Authorizations pursuant to Section 7(c) of the Natural Gas Act. The application requests authorization to expand capacity and increase pipeline connectivity at certain of Spire Storage’s natural gas storage facilities in Wyoming. On March 15, 2022, the FERC issued a final EIS for this project, concluding that construction and operation of the project would not result in significant environmental impacts and that project greenhouse gas emissions fall even below the FERC’s presumptive significance threshold for climate change impacts. On May 19, 2022, the FERC approved an order issuing certificates and granting abandonment as requested in the application. On June 21, 2022, following the submittal of an implementation plan, the FERC staff issued its limited notice to proceed with the project.

16. COMMITMENTS AND CONTINGENCIES

Commitments

The Company and the Utilities have entered into contracts with various counterparties, expiring on dates through 2039, for the storage, transportation, and supply of natural gas. Minimum payments required under the contracts in place at September 30, 2022, are estimated at $2,107.1, $1,224.7 and $723.1 for the Company, Spire Missouri and Spire Alabama, respectively. Additional contracts are generally entered into prior to or during the heating season of November through April. The Utilities recover their costs from customers in accordance with their PGA clauses or GSA riders.

A consolidated subsidiary is a limited partner in an unconsolidated partnership focusing on sustainability initiatives largely tied to the natural gas utility sector. Spire committed to contribute a total of $10.0 of capital to the partnership as and when requested by the general partner. As of September 30, 2022, Spire has contributed $1.9.

Contingencies

The Company and the Utilities account for contingencies, including environmental liabilities, in accordance with accounting standards under the loss contingency guidance of ASC Topic 450, *Contingencies*, when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated.

In addition to matters noted below, the Company and the Utilities are involved in other litigation, claims, and investigations arising in the normal course of business. Management, after discussion with counsel, believes the final outcome will not have a material effect on the statements of income, balance sheets, and statements of cash flows of the Company, Spire Missouri, or Spire Alabama. However, there is uncertainty in the valuation of pending claims and prediction of litigation results.

The Company and the Utilities own and operate natural gas distribution, transmission, and storage facilities, the operations of which are subject to various environmental laws, regulations, and interpretations. While environmental issues resulting from such operations arise in the ordinary course of business, such issues have not materially affected the Company's or Utilities' financial position and results of operations. As environmental laws, regulations, and their interpretations change, the Company or the Utilities may incur additional environmental liabilities that may result in additional costs, which may be material.

In the natural gas industry, many gas distribution companies have incurred environmental liabilities associated with sites they or their predecessor companies formerly owned or operated where manufactured gas operations took place. The Utilities each have former manufactured gas plant (MGP) operations in their respective service territories, some of which are discussed under the Spire Missouri and Spire Alabama headings below. To the extent costs are incurred associated with environmental remediation activities, the Utilities would request authority from their respective regulators to defer such costs (less any amounts received from insurance proceeds or as contributions from other potentially responsible parties (PRPs)) and collect them through future rates.

To date, costs incurred for all Spire MGP sites for investigation, remediation and monitoring have not been material. However, the amount of costs relative to future remedial actions at these and other sites is unknown and may be material. The actual future costs that Spire Missouri and Spire Alabama may incur could be materially higher or lower depending upon several factors, including whether remediation will be required, final selection and regulatory approval of any remedial actions, changing technologies and government regulations, the ultimate ability of other PRPs to pay, and any insurance recoveries.

In 2020, Spire retained an outside consultant to conduct probabilistic cost modeling of its former MGP sites in Missouri and Alabama. The purpose of this analysis was to develop an estimated range of probabilistic future liability for each of their MGP sites. That analysis, completed in March 2021, provided a range of demonstrated possible future expenditures to investigate, monitor and remediate the former MGP sites. Spire Missouri and Spire Alabama have recorded their best estimates of the probable expenditures that relate to these matters. The amount remains immaterial, and Spire Missouri, Spire Alabama and the Company do not expect potential liabilities that may arise from remediating these sites to have a material impact on their future financial condition or results of operations.

Spire Missouri

Spire Missouri has identified three former MGP sites in the city of St. Louis, Missouri (the "City") where costs have been incurred and claims have been asserted. Spire Missouri has enrolled two of the sites in the Missouri Department of Natural Resources (MoDNR) Brownfields/Voluntary Cleanup Program (BVCP). The third site is the result of an assertion by the United States Environmental Protection Agency (EPA).

In conjunction with redevelopment of the Carondelet Coke site, Spire Missouri and another former owner of the site entered into an agreement (the "Remediation Agreement") with the City development agencies, the developer, and an environmental consultant that obligates one of the City agencies and the environmental consultant to remediate the site and obtain a No Further Action (NFA) letter from the MoDNR. The Remediation Agreement also provides for a release of Spire Missouri and the other former site owner from certain liabilities related to the past and current environmental condition of the site and requires the developer and the environmental consultant to maintain certain insurance coverage, including remediation cost containment, premises pollution liability, and professional liability. The operative provisions of the Remediation Agreement were triggered on December 20, 2010, on which date Spire Missouri and the other former site owner, as full consideration under the Remediation Agreement, paid a small percentage of the cost of remediation of the site. The property was divided into seven parcels, and MoDNR NFA letters have been received for six of the parcels. Remediation is ongoing on the last parcel.

In a letter dated June 29, 2011, the Attorney General for the State of Missouri informed Spire Missouri that the MoDNR had completed an investigation of the second site, Station A. The Attorney General requested that Spire Missouri participate in the follow up investigations of the site. In a letter dated January 10, 2012, Spire Missouri stated that it would participate in future environmental response activities at the site in conjunction with other PRPs. Accordingly, Spire Missouri entered into a cost sharing agreement for remedial investigation with other PRPs. MoDNR never approved the agreement, so no remedial investigation took place.

Additionally, in correspondence dated November 30, 2016, Region 7 of the EPA has asserted that Spire Missouri is liable under Section 107(a) of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA) for alleged coal gas waste contamination at a third site, Station B. Spire Missouri and the site owner notified the EPA that information and data provided by the EPA to date does not rise to the level of documenting a threat to the public health or environment. As such, in March 2017 Spire Missouri requested more information from the EPA. Spire Missouri never received a response from the EPA.

Spire Missouri has notified its insurers that it seeks reimbursement for costs incurred in the past and future potential liabilities associated with these MGP sites. While some of the insurers have denied coverage and reserved their rights, Spire Missouri retains the right to seek potential reimbursements from them.

On March 10, 2015, Spire Missouri received a Section 104(e) information request under CERCLA from EPA Region 7 regarding the former Thompson Chemical/Superior Solvents site in the City. In turn, Spire Missouri issued a Freedom of Information Act (FOIA) request to the EPA on April 3, 2015, to identify the basis of the inquiry. The FOIA response from the EPA was received on July 15, 2015, and a response was provided to the EPA on August 15, 2015. Spire Missouri has received no further inquiry from the EPA regarding this matter.

In its western service area, Spire Missouri has six owned MGP sites enrolled in the BVCP, including Joplin MGP #1, St. Joseph MGP #1, Kansas City Coal Gas Station B, Kansas City Station A Railroad area, Kansas City Coal Gas Station A, and Independence MGP #2. Source removal has been conducted at all the owned sites since 2003 with the exception of Joplin. On September 15, 2016, a request was made with the MoDNR for a restrictive covenant use limitation with respect to Joplin. Remediation efforts at the six sites are at various stages of completion, ranging from groundwater monitoring and sampling following source removal activities to the aforementioned request for the Joplin site. As part of its participation in the BVCP, Spire Missouri communicates regularly with the MoDNR with respect to its remediation efforts and monitoring activities at these sites. On May 11, 2015, MoDNR approved the next phase of investigation at the Kansas City Station A Railroad area.

Spire Alabama

Spire Alabama is in the chain of title of nine former MGP sites, four of which it still owns, and five former manufactured gas distribution sites, one of which it still owns. All are located in the state of Alabama.

In 2011, a removal action was completed and a "no further action" letter was received at the Huntsville manufactured gas plant site pursuant to an Administrative Settlement Agreement and Order on Consent among the EPA, Spire Alabama and the current site owner.

In 2012, Spire Alabama responded to an EPA Request for Information Pursuant to Section 104 of CERCLA relating to the 35th Avenue Superfund Site located in North Birmingham, Jefferson County, Alabama. Spire Alabama was identified as a PRP under CERCLA for the cleanup of the site or costs the EPA incurs in cleaning up the site. At this point, Spire Alabama has not been provided information that would allow it to determine the extent, if any, of its potential liability with respect to the 35th Avenue Superfund Site and vigorously denies its inclusion as a PRP.

Assessments were performed by the EPA of the former MGP sites in Gadsden and Anniston, and NFA letters were received after each assessment.

Spire

In addition to those discussed above for Spire Missouri and Spire Alabama, Spire is aware of the following contingent matters.

Spire Marketing, along with many natural gas industry participants, faced the unprecedented effects of Winter Storm Uri in February 2021. Numerous natural gas producers and midstream operators were unable to deliver natural gas to market as they experienced wellhead freeze-offs, power outages and equipment failure due to the extreme weather. These events resulted in supply curtailments, and related notices of force majeure to excuse performance, from and to certain counterparties. Further, these events have made Spire Marketing subject to various commercial disputes (including regarding force majeure). As such, Spire Marketing has recorded an estimate of potential liabilities for damages based on communications with counterparties and the facts and circumstances surrounding each transaction. These estimates are adjusted as new facts emerge or settlement agreements are reached, and it is possible that final settlement amounts may materially differ from the current estimate.

17. LEASES

The lease agreement covering the Company's primary office space in St. Louis extends through February 2035, with an option to renew for an additional five years. Spire Alabama's lease agreement for office space in Birmingham extends through January 2037, with an option to renew for two additional five-year terms. The lease agreement covering Spire Marketing and Spire Storage office space in Houston extends through December 2028, with options to terminate three years earlier or to renew for an additional five years. The renewal options in the St. Louis and Houston leases are reasonably certain to be exercised and are included in the lease term used to determine the right-of-use assets and lease liabilities. The Company and its subsidiaries have other relatively minor rental arrangements for real estate and equipment with remaining terms of up to eight years.

Operating lease cost, cash flow and noncash information are shown in the following table.

	Spire			Spire Missouri			Spire Alabama		
	2022	2021	2020	2022	2021	2020	2022	2021	2020
Operating lease cost, including amounts capitalized	$ 7.4	$ 7.2	$ 8.7	$ 0.5	$ 0.4	$ 0.5	$ 2.1	$ 2.1	$ 3.5
Cash flow and noncash information about operating leases:									
Operating cash flows representing cash paid for amounts included in the measurement of lease liabilities	7.3	7.2	8.5	0.5	0.4	0.5	2.1	2.1	3.3
Right-of-use assets obtained in exchange for lease liabilities	24.6	—	71.1	1.1	—	2.1	23.5	—	10.0

The following table shows year-end balance sheet and weighted-average information about operating leases.

	Spire		Spire Missouri		Spire Alabama	
	2022	2021	2022	2021	2022	2021
Right-of-use assets	$ 73.7	$ 60.4	$ 1.7	$ 1.4	$ 20.2	$ 4.8
Lease liabilities, current	6.5	6.5	0.4	0.3	1.9	1.9
Lease liabilities, noncurrent	73.7	53.7	1.5	1.0	24.6	2.7
Weighted-average remaining lease term (in years)	15.0	15.3	5.1	4.5	14.3	2.3
Weighted-average discount rate	4.1%	4.2%	2.2%	2.5%	3.7%	2.2%

On the balance sheets, right-of-use assets are included in "Deferred Charges and Other Assets: Other," current lease liabilities are in "Current Liabilities: Other," and noncurrent lease liabilities are in "Deferred Credits and Other Liabilities: Other."

Following is a maturity analysis by fiscal year for operating lease liabilities as of September 30, 2022.

	Spire	Spire Missouri	Spire Alabama
2023	$ 6.7	$ 0.4	$ 1.9
2024	7.3	0.5	2.1
2025	7.4	0.4	2.1
2026	7.3	0.3	2.2
2027	7.3	0.2	2.3
Thereafter	72.8	0.2	24.1
Total undiscounted lease payments	108.8	2.0	34.7
Less present value discount	(28.6)	(0.1)	(8.2)
Total current and noncurrent lease liabilities	$ 80.2	$ 1.9	$ 26.5

There are no significant finance leases, short-term leases, subleases, variable lease payments, residual value guarantees, restrictions or covenants pertaining to leases.

The Company elected, for all asset classes, not to recognize right-of-use assets and lease liabilities for short-term leases. Instead, the lease payments for short-term leases are recognized in profit or loss on a straight-line basis over the lease term and variable lease payments are recognized in the period in which the obligation for those payments is incurred. The Company elected, for all asset classes, not to separate nonlease components from lease components and instead to account for each separate lease component and the nonlease components associated with that lease component as a single lease component.

The discount rate used for all the leases is the applicable incremental borrowing rate, which is the rate of interest that a lessee would have to pay to borrow on a collateralized basis over a similar term an amount equal to the lease payments in a similar economic environment. For a subsidiary lessee, the rate applicable to the subsidiary is used unless the lease terms are influenced by parent credit.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

There have been no changes in or disagreements on accounting and financial disclosure with Spire's, Spire Missouri's, or Spire Alabama's outside auditors that are required to be disclosed.

Item 9A. Controls and Procedures

Spire

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(e) and Rule 15d-15(e) under the Securities Exchange Act of 1934, as amended. Based upon such evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective.

Change in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during our fourth fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Spire Missouri

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(e) and Rule 15d-15(e) under the Securities Exchange Act of 1934, as amended. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during our fourth fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Spire Alabama

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the disclosure controls and procedures pursuant to Rule 13a-15(e) and Rule 15d-15(e) under the Securities Exchange Act of 1934, as amended. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during our fourth fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

The Management Reports on Internal Control Over Financial Reporting and the Reports of Independent Registered Public Accounting Firm are included in Item 8, Financial Statements and Supplementary Data.

Item 9B. Other Information

None.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information about:

- our directors is incorporated by reference from the discussion under Proposal 1 of our proxy statement to be filed on or about December 14, 2022 ("2022 proxy statement");
- our executive officers is reported in Part I of this Form 10-K;
- our Financial Code of Ethics is posted on our website, www.SpireEnergy.com, under Investors/Governance/Governance documents (http://investors.spireenergy.com/governance/governance-documents); and
- our Audit Committee, our Audit Committee financial experts, and submitting nominations to the Corporate Governance Committee

is incorporated by reference from the discussion in our 2022 proxy statement under the heading "Governance."

In addition, our Code of Business Conduct, Corporate Governance Guidelines, and charters for our Audit, Compensation and Corporate Governance Committees are available under "Governance documents" on our website, as indicated above, and a copy will be sent to any shareholder upon written request.

Item 11. Executive Compensation

Information about director and executive compensation is incorporated by reference from the discussion in our 2022 proxy statement under the headings "Directors' compensation" and "Executive compensation."

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information about:

- security ownership of certain beneficial owners and management and
- aggregate information regarding the Company's equity compensation plan

is incorporated by reference from the discussion in our 2022 proxy statement under "Beneficial ownership of Spire stock."

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information about:

- our policy and procedures for related party transactions and
- the independence of our directors

is included in our 2022 proxy statement under "Governance" and is incorporated by reference. There were no related party transactions in fiscal 2022.

Item 14. Principal Accounting Fees and Services

Information about fees paid to our independent registered public accountant and our policy for pre-approval of services provided by our independent registered public accountant is incorporated by reference from our 2022 proxy statement under "Fees of independent registered public accountant" and "Governance," respectively.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) (1) Financial Statements

See Item 8, Financial Statements and Supplementary Data, filed herewith, for a list of financial statements.

(2) Financial Statement Schedules

Schedules have been omitted because they are not applicable, related significance tests were not met, or the required data has been included in the financial statements or notes to financial statements.

(3) Exhibits

Exhibit Number	Description
2.01*	Agreement and Plan of Merger and Reorganization; filed as Appendix A to proxy statement/prospectus contained in the Company's Registration Statement on Form S-4 filed October 27, 2000, No. 333-48794.
3.01*	Articles of Incorporation of Spire Inc., as amended, effective as of April 28, 2016; filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on May 3, 2016.
3.02*	Amended Bylaws of Spire Inc., effective as of November 11, 2021; filed as Exhibit 3.2 to the Company's Current Report on Form 8-K on November 12, 2021.
3.03*	Spire Missouri Inc.'s Amended Articles of Incorporation, as amended, effective August 30, 2017; filed as Exhibit 3.1 to Spire Missouri's Current Report on Form 8-K on September 1, 2017.
3.04*	Amended Bylaws of Spire Missouri Inc., effective as of March 26, 2020; filed as Exhibit 3.1 to Spire Missouri's Current Report on Form 8-K on March 27, 2020.
3.05*	Articles of Amendment of the Articles of Incorporation of Spire Alabama Inc., dated September 1, 2017; filed as Exhibit 3.3 to Spire Alabama's Current Report on Form 8-K filed September 1, 2017.
3.06*	Amended Bylaws of Spire Alabama Inc. effective March 26, 2020; filed as Exhibit 3.2 to Spire Alabama's Current Report on Form 8-K on March 27, 2020.
3.07*	Certificate of Designations with respect to the Series A Preferred Stock, dated May 16, 2019; filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on May 21, 2019.
4.01*[3]	Mortgage and Deed of Trust, dated as of February 1, 1945, between Laclede Gas Company and Mississippi Valley Trust Company; filed as Exhibit 4.10 to the Company's Registration Statement on Form S-3 (No. 333-264799) on May 9, 2022.
4.02*[3]	Fourteenth Supplemental Indenture, dated as of October 26, 1976, between Laclede Gas and Mercantile Trust Company National Association; filed as Exhibit 4.11 to the Company's Registration Statement on Form S-3 (No. 333-264799) on May 9, 2022.
4.03*†[3]	Laclede Gas Board of Directors' Resolution dated August 28, 1986 which generally provides that the Board may delegate its authority in the adoption of certain employee benefit plan amendments to certain designated Executive Officers; filed as Exhibit 4.12 to Laclede Gas' Annual Report on Form 10-K for the fiscal year ended September 30, 1991.
4.04*†[2]	Indenture dated as of November 1, 1993, between Alagasco and NationsBank of Georgia, National Association, Trustee, ("Alagasco 1993 Indenture"); filed as Exhibit 4(k) to Alagasco's Registration Statement on Form S-3 (Registration No. 33-70466).
4.05*[3]	Twenty-Fourth Supplemental Indenture, dated as of June 1, 1999, between Laclede Gas and State Street Bank and Trust Company of Missouri, N.A., as trustee; filed as Exhibit 4.01 to Laclede Gas' Current Report on Form 8-K on June 4, 1999.
4.06*[3]	Twenty-Fifth Supplemental Indenture, dated as of September 15, 2000, between Laclede Gas and State Street Bank and Trust Company of Missouri, as trustee; filed as Exhibit 4.01 to Laclede Gas' Current Report on Form 8-K on September 29, 2000.
4.07*[3]	Laclede Gas' Board of Directors' Resolutions dated March 27, 2003, updating authority delegated pursuant to August 28, 1986 Laclede Gas resolutions; filed as Exhibit 4.19(a) to Laclede Gas' Annual Report on Form 10-K for the fiscal year ended September 30, 2003.

Exhibit Number	Description
4.08*[3]	Twenty-Eighth Supplemental Indenture, dated as of April 15, 2004, between Laclede Gas and UMB Bank & Trust, N.A., as trustee; filed as Exhibit 4.02 to Laclede Gas' Current Report on Form 8-K on April 28, 2004.
4.09*[3]	Twenty-Ninth Supplemental Indenture, dated as of June 1, 2006, between Laclede Gas and UMB Bank and Trust, N.A., as trustee; filed as Exhibit 4.1 to Laclede Gas' Current Report on Form 8-K on June 9, 2006.
4.10*[2]	Officers' Certificate, dated January 16, 2007, pursuant to Section 301 of the Alagasco 1993 Indenture setting forth the terms of the 5.90 percent Notes due January 15, 2037; filed as Exhibit 4.2 to Alagasco's Current Report on Form 8-K on January 16, 2007.
4.11*	Note Purchase Agreement, dated August 3, 2012, by and among the Company and the Purchasers listed in Schedule A thereto; filed as Exhibit 10.28 to the Company's Annual Report on Form 10-K for the fiscal year ended September 30, 2012.
4.12*[3]	Thirty-First Supplemental Indenture, dated as of March 15, 2013, between Laclede Gas and UMB Bank & Trust, N.A., as trustee; filed as Exhibit 4.1 to Laclede Gas' Form 10-Q for the quarter ended March 31, 2013.
4.13*[3]	Thirty-Second Supplemental Indenture, dated as of August 13, 2013, between Laclede Gas and UMB Bank & Trust, N.A., as trustee; filed as Exhibit 4.1 to Laclede Gas' Current Report on Form 8-K on August 13, 2013.
4.14*	Indenture, dated as of August 19, 2014, between the Company and UMB Bank & Trust, N.A., as trustee; filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on August 19, 2014.
4.15*	First Supplemental Indenture, dated as of August 19, 2014, between the Company and UMB Bank & Trust, N.A., as trustee (including Form of Floating Rate Senior Notes due 2017, Form of 2.55% Senior Notes due 2019 and Form of 4.70% Senior Notes due 2044); filed as Exhibit 4.2 to the Company's Current Report on Form 8-K on August 19, 2014.
4.16*[2]	Master Note Purchase Agreement, dated as of June 5, 2015, among Alagasco and certain institutional purchasers; filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015.
4.17*	Second Supplemental Indenture, dated as of February 27, 2017, between Spire Inc. and UMB Bank & Trust, N.A., as Trustee (including Form of 3.543% Senior Notes due 2024); filed as Exhibit 4.2 to the Company's Current Report on Form 8-K on February 27, 2017.
4.18*	Master Note Purchase Agreement dated June 20, 2016, among Spire Inc. and certain institutional purchasers party thereto; filed as Exhibit 4.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017.
4.19*	First Supplement to Master Note Purchase Agreement dated as of March 15, 2017, among Spire Inc. and certain institutional purchasers party thereto; filed as Exhibit 4.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017.
4.20*[3]	Bond Purchase Agreement dated March 20, 2017, among Laclede Gas Company and certain institutional purchasers party thereto; filed as Exhibit 4.4 to the Laclede Gas' Quarterly Report on Form 10-Q for the quarter ended March 31, 2017.
4.21*	First Supplement to Master Note Purchase Agreement, dated as of December 1, 2017, between Spire Alabama Inc. and certain institutional investors; filed as Exhibit 4.01 to the Company's Quarterly Report on Form 10-Q for the quarter ended December 31, 2017.
4.22*	Second Supplement to Master Note Purchase Agreement, dated as of January 15, 2019, between Spire Alabama Inc. and certain institutional investors; filed as Exhibit 4.1 to Spire Alabama's Current Report on Form 8-K on January 22, 2019.

Exhibit Number	Description
4.23*	Deposit Agreement, dated as of May 21, 2019, among the Company, Computershare Inc. and Computershare Trust Company, N.A., acting jointly as depositary, and the holders from time to time of the depositary receipts described therein; filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on May 21, 2019.
4.24*	Form of depositary receipt representing the Depositary Shares; filed as Exhibit A to Exhibit 4.1 to the Company's Current Report on Form 8-K on May 21, 2019.
4.25*	Form of Certificate representing the Series A Preferred Stock; filed as Exhibit A to Exhibit 3.1 to the Company's Current Report on Form 8-K on May 21, 2019.
4.26*	Thirty-Third Supplemental Indenture, dated as of September 15, 2017, between Spire Missouri Inc. and UMB Bank & Trust, N.A., as trustee, filed as Exhibit 4.28 to Spire Missouri's Annual Report on Form 10-K for the fiscal year ended September 30, 2019.
4.27*	Thirty-Fourth Supplemental Indenture, dated as of November 12, 2019, between Spire Missouri Inc. and UMB Bank & Trust, N.A., as trustee; filed as Exhibit 4.1 to Spire Missouri's Quarterly Report on Form 10-Q for the quarter ended December 31, 2019.
4.28*	Third Supplement to Master Note Purchase Agreement, dated as of December 2, 2019, between Spire Alabama Inc. and certain institutional investors; filed as Exhibit 4.1 to Spire Alabama's Current Report on Form 8-K on December 4, 2019.
4.29*	Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934; filed as Exhibit 4.29 to the Company's Annual Report on Form 10-K for the fiscal year ended September 30, 2019.
4.30*	Fourth Supplement to Master Note Purchase Agreement, dated as of December 15, 2020, between Spire Alabama Inc. and certain institutional investors; filed as Exhibit 4.1 to Spire Alabama's Current Report on Form 8-K on December 18, 2020.
4.31*	Indenture (For Unsecured Debt Securities), dated as of February 16, 2021, between the Company and U.S. Bank National Association, as trustee; filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on February 16, 2021.
4.32*	First Supplemental Indenture, dated as of February 16, 2021, between the Company and U.S. Bank National Association, as trustee; filed as Exhibit 4.2 to the Company's Current Report on Form 8-K on February 16, 2021.
4.33*	Form of Series A 0.75% Remarketable Senior Note due 2026; included in Exhibit 4.2 to the Company's Current Report on Form 8-K on February 16, 2021.
4.34*	Purchase Contract and Pledge Agreement, dated as of February 16, 2021, between the Company and U.S. Bank National Association, as purchase contract agent, collateral agent, custodial agent and securities intermediary; filed as Exhibit 4.4 to the Company's Current Report on Form 8-K on February 16, 2021.
4.35*	Form of Remarketing Agreement; included in Exhibit 4.4 to the Company's Current Report on Form 8-K on February 16, 2021.
4.36*	Form of Corporate Unit; included in Exhibit 4.4 to the Company's Current Report on Form 8-K on February 16, 2021.
4.37*	Form of Treasury Unit; included in Exhibit 4.4 to the Company's Current Report on Form 8-K on February 16, 2021.
4.38*	Thirty-Fifth Supplemental Indenture, dated as of May 20, 2021, between Spire Missouri and UMB Bank & Trust, N.A., as trustee; filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on May 20, 2021.
4.39*	Form of 3.300% Series First Mortgage Bonds due 2051; included in Exhibit 4.1 to the Company's Current Report on Form 8-K on May 20, 2021.
4.40*	Thirty-Sixth Supplemental Indenture, dated as of December 7, 2021, between Spire Missouri and UMB Bank & Trust, N.A., as trustee; filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on December 7, 2021.
4.41*	Form of First Mortgage Bonds, Floating Rate Series due 2024; included in Exhibit 4.1 to the Company's Current Report on Form 8-K on December 7, 2021.
4.42*	Thirty-Seventh Supplemental Indenture, dated as of May 2, 2022, between Spire Missouri and UMB Bank & Trust, N.A., as trustee; filed as Exhibit 4.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2022.
4.43*	Fifth Supplement to Master Note Purchase Agreement, dated as of October 13, 2022, between Spire Alabama Inc. and certain institutional investors, filed as Exhibit 4.1 to the Company's and Spire Alabama's Current Report on Form 8-K on October 19, 2022.

Exhibit Number	Description
10.01*†[3]	**Form of Indemnification Agreement between Laclede Gas and its Directors and Officers; filed as Exhibit 10.13 to Laclede Gas' Annual Report on Form 10-K for the fiscal year ended September 30, 1990.**
10.02*†[3]	**Salient Features of Laclede Gas' Deferred Income Plan for Directors and Selected Executives, including amendments adopted by the Board of Directors on July 26, 1990; filed as Exhibit 10.12 to Laclede Gas' Annual Report on Form 10-K for the fiscal year ended September 30, 1991.**
10.03*†[3]	**Amendment to Laclede Gas' Deferred Income Plan for Directors and Selected Executives, adopted by the Board of Directors on August 27, 1992; filed as Exhibit 10.12a to Laclede Gas' Annual Report on Form 10-K for the fiscal year ended September 30, 1992.**
10.04*[3]	**Amendment and Restatement of Retirement Plan for Non-Employee Directors of Laclede Gas as of November 1, 2002; filed as Exhibit 10.08c to Laclede Gas' Annual Report on Form 10-K for the fiscal year ended September 30, 2002.**
10.05*[3]	**Amendment to Terms of Retirement Plan for Non-Employee Directors of Laclede Gas as of October 1, 2004; filed as Exhibit 10.2 to Laclede Gas' Quarterly Report on Form 10-Q for the quarter ended June 30, 2004.**
10.06*	**Form of Non-Qualified Stock Option Award Agreement with Mandatory Retirement Provisions; filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on November 5, 2004.**
10.07*	**Form of Non-Qualified Stock Option Award Agreement without Mandatory Retirement Provisions; filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on November 5, 2004.**
10.08*[3]	Automated Meter Reading Services Agreement with Amendment dated as of July 1, 2017, between Landis+Gyr Technology, Inc., formerly known as Cellnet Technology, Inc., and Laclede Gas Company; filed as Exhibit 10.08 to the Company's Annual Report on Form 10-K for the fiscal year ended September 30, 2020.
10.09*[3]	**Restated Laclede Gas Supplemental Retirement Benefit Plan, as amended and restated as of January 1, 2005; filed as Exhibit 10.06 to Laclede Gas' Quarterly Report on Form 10-Q for the quarter ended December 31, 2008.**
10.10*[3]	**Laclede Gas Supplemental Retirement Benefit Plan II, effective as of January 1, 2005; filed as Exhibit 10.7 to Laclede Gas' Quarterly Report on Form 10-Q for the quarter ended December 31, 2008.**
10.11*[3]	**Salient Features of Laclede Gas' Deferred Income Plan II for Directors and Selected Executives (as amended and restated effective as of January 1, 2005); filed as Exhibit 10.1 to Laclede Gas' Quarterly Report on Form 10-Q for the quarter ended December 31, 2008.**
10.12*	**Salient Features of the Company's Deferred Income Plan for Directors and Selected Executives (effective as of January 1, 2005); filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended December 31, 2008.**
10.13*	**The Company's Form of Restricted Stock Award Agreement; filed as Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q for the quarter ended December 31, 2008.**
10.14*[3]	**The Laclede Group Management Continuity Protection Plan, effective as of January 1, 2005; filed as Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended December 31, 2008.**
10.15*	**Form of Management Continuity Protection Agreement; filed as Exhibit 10.5a to the Company's Quarterly Report on Form 10-Q for the quarter ended December 31, 2008.**
10.16*[3]	**The Laclede Group 2011 Management Continuity Protection Plan; filed as Exhibit 10.25 to the Company's Annual Report on Form 10-K for the fiscal year ended September 30, 2010.**
10.17*	**Form of Agreement under the Company's 2011 Management Continuity Protection Plan; filed as Exhibit 10.25a to the Company's Annual Report on Form 10-K for the fiscal year ended September 30, 2010.**
10.18*	**The Company's Form of Performance Contingent Restricted Stock Unit Award Agreement; filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended December 31, 2012.**
10.19*[3]	**Laclede Gas Cash Balance Supplemental Retirement Benefit Plan, effective as of January 1, 2009; filed as Exhibit 10.19 to Laclede Gas' Annual Report on Form 10-K for the fiscal year ended September 30, 2012.**

Exhibit Number	Description
10.20*	Lease Agreement, dated January 21, 2014, between the Company, as Tenant, and Market 700, LLC, as Landlord; filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 27, 2014.
10.21*	**The Company's Deferred Income Plan for Directors and Selected Executives, as Amended and Restated as of January 1, 2015; filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on November 4, 2014.**
10.22*[1]	**The Laclede Group 2015 Equity Incentive Plan; filed as the Appendix to the Company's Definitive Proxy Statement on Form DEF 14A on December 19, 2014.**
10.23*[1]	**The Laclede Group, Inc. Annual Incentive Plan, as Amended; filed as Appendix to the Company's Definitive Proxy Statement on Schedule 14A on December 18, 2015.**
10.24*[2 3]	Loan Agreement, dated December 14, 2016, by and among Spire Inc., Alabama Gas Corporation, Laclede Gas Company, and the several banks party thereto, including Wells Fargo Bank, National Association, as Administrative Agent; JPMorgan Chase Bank, N.A. and U.S. Bank National Association, as Co-Syndication Agents; Wells Fargo Securities, LLC, JPMorgan Chase Bank, N.A., and U.S. Bank National Association, as Joint Lead Arrangers and Joint Bookrunners; and Bank of America, N.A., Credit Suisse AG, Cayman Islands Branch, Morgan Stanley Bank, N.A., Regions Bank, Royal Bank of Canada, and TD Bank, N.A., as Documentation Agents; filed as Exhibit 99.1 to the Company's Current Report on Form 8-K on December 16, 2016.
10.25*	Commercial Paper Dealer Agreement, dated December 21, 2016, between Spire Inc. and Wells Fargo Securities, LLC; filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended December 31, 2016.
10.26*	Commercial Paper Dealer Agreement, dated December 21, 2016, between Spire Inc. and Credit Suisse Securities (USA) LLC; filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended December 31, 2016.
10.27*	**Spire Inc. Executive Severance Plan; filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on May 2, 2017.**
10.28*[1]	**Amendment 1 to The Laclede Group Annual Incentive Plan effective January 1, 2018; filed as Exhibit 10.53 to the Company's Annual Report on Form 10-K for the fiscal year ended September 30, 2017.**
10.29*[1]	**Amendment 1 to The Laclede Group 2015 Equity Incentive Plan effective January 1, 2018; filed as Exhibit 10.54 to the Company's Annual Report on Form 10-K for the fiscal year ended September 30, 2017.**
10.30*	**Amendment 1 to Spire Inc. Executive Severance Plan effective January 1, 2018; filed as Exhibit 10.55 to the Company's Annual Report on Form 10-K for the fiscal year ended September 30, 2017.**
10.31*[1]	**Amendment 1 to The Laclede Group 2011 Management Continuity Protection Plan effective January 18, 2018; filed as Exhibit 10.56 to the Company's Annual Report on Form 10-K for the fiscal year ended September 30, 2017.**
10.32*	First Amendment to Loan Agreement, dated as of October 31, 2018, by and among Spire Inc., a Missouri corporation, Spire Alabama Inc. (formerly Alabama Gas Corporation), an Alabama corporation, and Spire Missouri Inc. (formerly Laclede Gas Company), a Missouri corporation, the Banks from time to time party thereto, and Wells Fargo Bank, National Association, as Administrative Agent for the Banks; filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on November 6, 2018.
10.33*	**Spire Deferred Income Plan, Amended and Restated Effective January 1, 2019; filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2019.**
10.34*	**The Company's Form of Restricted Stock Award Agreement; filed as Exhibit 10.38 to the Company's Annual Report on Form 10-K for the fiscal year ended September 30, 2019.**
10.35*	**The Company's Form of Restricted Stock Unit Award Agreement; filed as Exhibit 10.39 to the Company's Annual Report on Form 10-K for the fiscal year ended September 30, 2019.**
10.36*	**The Company's Form of Performance Contingent Stock Unit Award Agreement; filed as Exhibit 10.40 to the Company's Annual Report on Form 10-K for the fiscal year ended September 30, 2019.**

Exhibit Number	Description
10.37*	Loan Agreement, dated March 26, 2020, by and among Spire Inc., as the Borrower, the lenders from time to time party thereto, as Banks, including U.S. Bank National Association, as the Administrative Agent, and TD Bank, N.A., as Documentation Agent; filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on March 27, 2020.
10.38*	Loan Agreement, dated March 23, 2021, by and among Spire Missouri Inc., as the Borrower, and five banks including U.S. Bank National Association, as the Administrative Agent; filed as Exhibit 10.1 to the Company and Spire Missouri's Current Report on Form 8-K on March 23, 2021.
10.39*	Amended and Restated Loan Agreement, dated July 22, 2022, among Spire Inc., Spire Missouri Inc., Spire Alabama Inc., Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto as Banks; filed as Exhibit 99.1 to the Company's Current Report on Form 8-K on July 28, 2022.
10.40*	Equity Distribution Agreement of the Company, dated as of February 6, ,2019; filed as Exhibit 1.1 to the Company's Current Report on Form 8-K on February 6, 2019.
10.41*	Letter Agreement to the Equity Distribution Agreement of the Company, dated as of May 14, 2019; filed as Exhibit 1.1 to the Company's Current Report on Form 8-K on May 14, 2019.
10.42*	Second Letter Agreement to the Equity Distribution Agreement of the Company, dated as of May 10, 2022, dated as of May 9, 2022; filed as Exhibit 1.1 to the Company's Current Report on Form 8-K on May 10, 2022.
21	Subsidiaries of the Company.
23.1	Consent of Independent Registered Public Accounting Firm of the Company.
23.2	Consent of Independent Registered Public Accounting Firm of Spire Missouri Inc.
23.3	Consent of Independent Registered Public Accounting Firm of Spire Alabama Inc.
31.1	Certifications under Rule 13a-14(a) of the CEO and CFO of the Company.
31.2	Certifications under Rule 13a-14(a) of the CEO and CFO of Spire Missouri Inc.
31.3	Certifications under Rule 13a-14(a) of the CEO and CFO of Spire Alabama Inc.
32.1	Section 1350 Certifications under Rule 13a-14(b) of the CEO and CFO of the Company.
32.2	Section 1350 Certifications under Rule 13a-14(b) of the CEO and CFO of Spire Missouri Inc.
32.3	Section 1350 Certifications under Rule 13a-14(b) of the CEO and CFO of Spire Alabama Inc.
101	Interactive Data Files including the following information from the Annual Report on Form 10-K for the fiscal year ended September 30, 2022, formatted in inline extensible business reporting language ("Inline XBRL"): (i) Cover Page Interactive Data and (ii) the Financial Statements listed on the first page of Item 8.
104	Cover Page Interactive Data File (formatted in Inline XBRL and included in the Interactive Data Files submitted under Exhibit 101).

* Incorporated herein by reference and made a part hereof. Spire Inc. File No. 1-16681. Spire Missouri Inc. File No. 1-1822. Spire Alabama Inc. File No. 2-38960.

† Paper exhibit.

1 The Laclede Group, Inc. changed its name to Spire Inc. effective April 28, 2016.

2 Alabama Gas Corporation ("Alagasco") changed its name to Spire Alabama Inc. effective September 1, 2017.

3 Laclede Gas Company changed its name to Spire Missouri Inc. effective August 30, 2017.

Bold items reflect management contracts or compensatory plans or arrangements.

Item 16. Form 10-K Summary

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Spire Inc.

Date November 16, 2022

By /s/ Steven P. Rasche
Steven P. Rasche
Executive Vice President
and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date	Signature	Title
November 16, 2022	/s/ Suzanne Sitherwood Suzanne Sitherwood	Director, President and Chief Executive Officer (Principal Executive Officer)
November 16, 2022	/s/ Steven P. Rasche Steven P. Rasche	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)
November 16, 2022	/s/ Edward L. Glotzbach Edward L. Glotzbach	Chairman of the Board
November 16, 2022	/s/ Mark A. Borer Mark A. Borer	Director
November 16, 2022	/s/ Maria V. Fogarty Maria V. Fogarty	Director
November 16, 2022	/s/ Carrie J. Hightman Carrie J. Hightman	Director
November 16, 2022	/s/ Rob L. Jones Rob L. Jones	Director
November 16, 2022	/s/ Brenda D. Newberry Brenda D. Newberry	Director
November 16, 2022	/s/ Stephen S. Schwartz Stephen S. Schwartz	Director
November 16, 2022	/s/ John P. Stupp Jr. John P. Stupp Jr.	Director
November 16, 2022	/s/ Mary Ann Van Lokeren Mary Ann Van Lokeren	Director

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Spire Missouri Inc.

Date	November 16, 2022	By	/s/ Timothy W. Krick
			Timothy W. Krick Controller and Chief Accounting Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date	Signature	Title
November 16, 2022	/s/ Suzanne Sitherwood Suzanne Sitherwood	Chairman of the Board
November 16, 2022	/s/ Steven L. Lindsey Steven L. Lindsey	Director and Chief Executive Officer (Principal Executive Officer)
November 16, 2022	/s/ Adam W. Woodard Adam W. Woodard	Chief Financial Officer and Treasurer (Principal Financial Officer)
November 16, 2022	/s/ Timothy W. Krick Timothy W. Krick	Controller and Chief Accounting Officer (Principal Accounting Officer)
November 16, 2022	/s/ Scott B. Carter Scott B. Carter	Director and President
November 16, 2022	/s/ Mark C. Darrell Mark C. Darrell	Director
November 16, 2022	/s/ Steven P. Rasche Steven P. Rasche	Director

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Spire Alabama Inc.

Date November 16, 2022	By /s/ Timothy W. Krick Timothy W. Krick Chief Accounting Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date	Signature	Title
November 16, 2022	/s/ Suzanne Sitherwood Suzanne Sitherwood	Chairman of the Board
November 16, 2022	/s/ Steven L. Lindsey Steven L. Lindsey	Director and Chief Executive Officer (Principal Executive Officer)
November 16, 2022	/s/ Adam W. Woodard Adam W. Woodard	Chief Financial Officer and Treasurer (Principal Financial Officer)
November 16, 2022	/s/ Timothy W. Krick Timothy W. Krick	Chief Accounting Officer (Principal Accounting Officer)
November 16, 2022	/s/ Scott B. Carter Scott B. Carter	Director
November 16, 2022	/s/ Mark C. Darrell Mark C. Darrell	Director
November 16, 2022	/s/ Joseph B. Hampton Joseph B. Hampton	Director and President
November 16, 2022	/s/ Steven P. Rasche Steven P. Rasche	Director

Information for our shareholders

Annual meeting

The annual meeting of shareholders of Spire Inc. will be held on Thursday, Jan. 26, 2023, at 8:30 a.m. Central Standard Time, online at www.virtualshareholdermeeting.com/SR2022. The formal notice of the meeting, proxy statement, form of proxy and this annual report were made available to shareholders on or about Dec. 14, 2022. The proxy statement and annual report may be found on our website by visiting SpireEnergy.com.

Transfer agent and registrar

Spire's shareholder records are maintained by its transfer agent, Computershare Trust Company, N.A. Inquiries relating to stockholder records, stock transfers, address changes, dividend payments, lost certificates and other administrative matters should be addressed to:

Computershare Trust Company, N.A.
P.O. Box 43006
Providence, RI 02940-3006
800-884-4225

Primary business office

Spire Inc.
700 Market Street
St. Louis, MO 63101
314-342-0500
SpireEnergy.com

Dividend reinvestment and stock purchase plan

Spire's dividend reinvestment and stock purchase plan provides common shareholders the opportunity to purchase additional common stock by automatically reinvesting dividends or by making additional cash payments. Shareholders who are interested in obtaining more information, including an enrollment card, may contact:

Computershare Trust Company, N.A.
P.O. Box 43006
Providence, RI 02940-3006
800-884-4225

Stock and dividends

Spire Inc. common stock is listed on the New York Stock Exchange (NYSE) under the symbol SR. There were 52,494,543 shares outstanding as of Sept. 30, 2022. Spire has paid a cash dividend continuously since 1946. Dividends are typically paid on the second business day of January, April, July and October. The current annualized dividend is $2.88 per share, effective with the quarterly payment on Jan. 4, 2023.

The high and low trading prices and dividends declared on common stock for the past two years were:

Fiscal 2022	High	Low	Dividends declared
1st Quarter	$ 66.32	$ 59.60	$ 0.685
2nd Quarter	72.41	61.89	0.685
3rd Quarter	79.24	69.84	0.685
4th Quarter	77.68	62.22	0.685

Fiscal 2021	High	Low	Dividends declared
1st Quarter	$ 68.01	$ 51.82	$ 0.65
2nd Quarter	75.78	59.29	0.65
3rd Quarter	77.95	69.77	0.65
4th Quarter	74.46	60.05	0.65

Inquiries

Copies of Spire's Forms 10-K, 10-Q and 8-K filed with the Securities and Exchange Commission, quarterly updates, news releases and other investor information are available at no charge by visiting SpireEnergy.com or by contacting Investor Relations:

Scott W. Dudley Jr.
Managing Director, Investor Relations
Scott.Dudley@SpireEnergy.com
314-342-0878

For media inquiries, contact Corporate Communications:

Jessica B. Willingham
Senior Vice President, Chief Communications and Marketing Officer
Jessica.Willingham@SpireEnergy.com
314-342-3300

Spire Inc.
700 Market Street
St. Louis, MO 63101

SpireEnergy.com

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended September 30, 2022

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-10042

Atmos Energy Corporation

(Exact name of registrant as specified in its charter)

Texas and Virginia	**75-1743247**
(State or other jurisdiction of incorporation or organization)	*(IRS employer identification no.)*
1800 Three Lincoln Centre	
5430 LBJ Freeway	
Dallas, Texas	**75240**
(Address of principal executive offices)	*(Zip code)*

Registrant's telephone number, including area code:
(972) 934-9227

Securities registered pursuant to Section 12(b) of the Act:

Table of each class		Trading Symbol	Name of each exchange on which registered
Common stock	No Par Value	ATO	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☑

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of the common voting stock held by non-affiliates of the registrant as of the last business day of the registrant's most recently completed second fiscal quarter, March 31, 2022, was $16,491,263,629.

As of November 7, 2022, the registrant had 140,900,576 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Definitive Proxy Statement to be filed for the Annual Meeting of Shareholders on February 8, 2023 are incorporated by reference into Part III of this report.

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GLOSSARY OF KEY TERMS

Adjusted diluted net income per share	Non-GAAP measure defined as diluted net income per share before the one-time, non-cash income tax benefit
Adjusted net income	Non-GAAP measure defined as net income before the one-time, non-cash income tax benefit
AFUDC	Allowance for funds used during construction
AOCI	Accumulated Other Comprehensive Income
ARM	Annual Rate Mechanism
ATO	Trading symbol for Atmos Energy Corporation common stock on the NYSE
Bcf	Billion cubic feet
COSO	Committee of Sponsoring Organizations of the Treadway Commission
DARR	Dallas Annual Rate Review
ERISA	Employee Retirement Income Security Act of 1974
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
GRIP	Gas Reliability Infrastructure Program
GSRS	Gas System Reliability Surcharge
LIBOR	London Interbank Offered Rate
LTIP	1998 Long-Term Incentive Plan
Mcf	Thousand cubic feet
MDWQ	Maximum daily withdrawal quantity
Mid-Tex ATM Cities	Represents a coalition of 47 incorporated cities or approximately 10 percent of the Mid-Tex Division's customers.
Mid-Tex Cities	Represents all incorporated cities other than Dallas and Mid-Tex ATM Cities, or approximately 72 percent of the Mid-Tex Division’s customers.
MMcf	Million cubic feet
Moody’s	Moody’s Investor Service, Inc.
NGPA	Natural Gas Policy Act of 1978
NTSB	National Transportation Safety Board
NYSE	New York Stock Exchange
PHMSA	Pipeline and Hazardous Materials Safety Administration
PPA	Pension Protection Act of 2006
PRP	Pipeline Replacement Program
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
RSC	Rate Stabilization Clause
S&P	Standard & Poor’s Corporation
SAVE	Steps to Advance Virginia Energy
SEC	United States Securities and Exchange Commission
SIP	System Integrity Program
SIR	System Integrity Rider
SOFR	Secured Overnight Financing Rate
SRF	Stable Rate Filing
SSIR	System Safety and Integrity Rider
TCJA	Tax Cuts and Jobs Act of 2017
WNA	Weather Normalization Adjustment

PART I

The terms "we," "our," "us," "Atmos Energy" and the "Company" refer to Atmos Energy Corporation and its subsidiaries, unless the context suggests otherwise.

ITEM 1. *Business.*

Overview and Strategy

Atmos Energy Corporation, headquartered in Dallas, Texas, and incorporated in Texas and Virginia, is the country's largest natural-gas-only distributor based on number of customers. We safely deliver reliable, affordable, efficient and abundant natural gas through regulated sales and transportation arrangements to approximately 3.3 million residential, commercial, public authority and industrial customers in eight states located primarily in the South. We also operate one of the largest intrastate pipelines in Texas based on miles of pipe.

Atmos Energy's vision is to be the safest provider of natural gas services. We will be recognized for exceptional customer service, for being a great employer and for achieving superior financial results.

Since 2011, our operating strategy has focused on modernizing our business and infrastructure while reducing regulatory lag. This operating strategy supports continued investment in safety, innovation, environmental sustainability and our communities.

Operating Segments

As of September 30, 2022, we manage and review our consolidated operations through the following reportable segments:

- The *distribution segment* is primarily comprised of our regulated natural gas distribution and related sales operations in eight states.
- The *pipeline and storage segment* is comprised primarily of the pipeline and storage operations of our Atmos Pipeline-Texas division and our natural gas transmission operations in Louisiana.

Distribution Segment Overview

The following table summarizes key information about our six regulated natural gas distribution divisions, presented in order of total rate base.

Division	Service Areas	Communities Served	Customer Meters
Mid-Tex	Texas, including the Dallas/Fort Worth Metroplex	550	1,822,036
Kentucky/Mid-States	Kentucky	230	184,547
	Tennessee		162,392
	Virginia		24,898
Louisiana	Louisiana	270	376,515
West Texas	Amarillo, Lubbock, Midland	80	329,378
Mississippi	Mississippi	110	273,934
Colorado-Kansas	Colorado	170	127,565
	Kansas		140,959

We operate in our service areas under terms of non-exclusive franchise agreements granted by the various cities and towns that we serve. At September 30, 2022, we held 1,028 franchises having terms generally ranging from five to 35 years. A significant number of our franchises expire each year, which require renewal prior to the end of their terms. Historically, we have successfully renewed these franchises and believe that we will continue to be able to renew our franchises as they expire.

Revenues in this operating segment are established by regulatory authorities in the states in which we operate. These rates are intended to be sufficient to cover the costs of conducting business, including a reasonable return on invested capital. In addition, we transport natural gas for others through our distribution systems.

Rates established by regulatory authorities often include cost adjustment mechanisms for costs that (i) are subject to significant price fluctuations compared to our other costs, (ii) represent a large component of our cost of service and (iii) are generally outside our control.

Purchased gas cost adjustment mechanisms represent a traditional and common form of cost adjustment mechanism. Purchased gas cost adjustment mechanisms provide a method of recovering purchased gas costs on an ongoing basis without filing a rate case because they provide a dollar-for-dollar offset to increases or decreases in the cost of natural gas. Therefore, although substantially all of our distribution operating revenues fluctuate with the cost of gas that we purchase, distribution operating income is generally not affected by fluctuations in the cost of gas.

Additionally, some jurisdictions have performance-based ratemaking adjustments to provide incentives to minimize purchased gas costs through improved storage management and use of financial instruments to reduce volatility in gas costs. Under the performance-based ratemaking adjustments, purchased gas costs savings are shared between the Company and its customers.

Our supply of natural gas is provided by a variety of suppliers, including independent producers and marketers. The gas is delivered into our systems by various pipeline companies, withdrawals of gas from proprietary and contracted storage assets and base load and peaking arrangements, as needed.

Supply arrangements consist of both base load and peaking quantities and are contracted from our suppliers on a firm basis with various terms at market prices. Base load quantities are those that flow at a constant level throughout the month and peaking quantities provide the flexibility to change daily quantities to match increases or decreases in requirements related to weather conditions.

Except for local production purchases, we select our natural gas suppliers through a competitive bidding process by periodically requesting proposals from suppliers. We select these suppliers based on their ability to reliably deliver gas supply to our designated firm pipeline receipt points at the lowest reasonable cost. Major suppliers during fiscal 2022 were ConocoPhillips Company, EnLink Gas Marketing LP, Enterprise Navitas Midstream Midland Basin LLC, EOG Resources, Inc., Hartree Partners, L.P., Sequent Energy Management LLC, Symmetry Energy Solutions, LLC, Targa Gas Marketing LLC, Texla Energy Management, Inc. and Twin Eagle Resource Management, LLC.

The combination of base load and peaking agreements, coupled with the withdrawal of gas held in storage, allows us the flexibility to adjust to changes in weather, which minimizes our need to enter into long-term firm commitments. We estimate our peak-day availability of natural gas supply to be approximately 4.4 Bcf. The peak-day demand for our distribution operations in fiscal 2022 was on February 3, 2022, when sales to customers reached approximately 3.6 Bcf.

Currently, our distribution divisions utilize 38 pipeline transportation companies, both interstate and intrastate, to transport our natural gas. The pipeline transportation agreements are firm and many of them have “pipeline no-notice” storage service, which provides for daily balancing between system requirements and nominated flowing supplies. These agreements have been negotiated with the shortest term necessary while still maintaining our right of first refusal. The natural gas supply for our Mid-Tex Division is delivered primarily by our APT Division.

To maintain our deliveries to high priority customers, we have the ability, and have exercised our right, to interrupt or curtail service to certain customers pursuant to contracts and applicable state regulations or statutes. Our customers’ demand on our system is not necessarily indicative of our ability to meet current or anticipated market demands or immediate delivery requirements because of factors such as the physical limitations of gathering, storage and transmission systems, the duration and severity of cold weather, the availability of gas reserves from our suppliers, the ability to purchase additional supplies on a short-term basis and actions by federal and state regulatory authorities. Interruption and curtailment rights provide us the flexibility to meet the human-needs requirements of our customers on a reliable basis. Priority allocations imposed by federal and state regulatory agencies, as well as other factors beyond our control, may affect our ability to meet the demands of some of our customers.

Pipeline and Storage Segment Overview

Our pipeline and storage segment consists of the pipeline and storage operations of APT and our natural gas transmission operations in Louisiana. APT is one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas-producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Barnett Shale, the Texas Gulf Coast and the Permian Basin of West Texas. Through its system, APT provides transportation and storage services to our Mid-Tex Division, other third party local distribution companies, industrial and electric generation customers, marketers and producers. As part of its pipeline operations, APT owns and operates five underground storage reservoirs in Texas.

Revenues earned from transportation and storage services for APT are subject to traditional ratemaking governed by the RRC. Rates are updated through periodic filings made under Texas’ GRIP. GRIP allows us to include in our rate base annually approved capital costs incurred in the prior calendar year provided that we file a complete rate case at least once every five years; the most recent of which was completed in August 2017. APT's existing regulatory mechanisms allow certain transportation and storage services to be provided under market-based rates.

Our natural gas transmission operations in Louisiana are comprised of a 21-mile pipeline located in the New Orleans, Louisiana area that is primarily used to aggregate gas supply for our distribution division in Louisiana under a long-term contract and, on a more limited basis, to third parties. The demand fee charged to our Louisiana distribution division for these services is subject to regulatory approval by the Louisiana Public Service Commission. We also manage two asset management plans that serve distribution affiliates of the Company, which have been approved by applicable state regulatory commissions. Generally, these asset management plans require us to share with our distribution customers a significant portion of the cost savings earned from these arrangements.

Ratemaking Activity

Overview

The method of determining regulated rates varies among the states in which our regulated businesses operate. The regulatory authorities have the responsibility of ensuring that utilities in their jurisdictions operate in the best interests of customers while providing utility companies the opportunity to earn a reasonable return on their investment. Generally, each regulatory authority reviews rate requests and establishes a rate structure intended to generate revenue sufficient to cover the costs of conducting business, including a reasonable return on invested capital.

Our rate strategy focuses on reducing or eliminating regulatory lag, obtaining adequate returns and providing stable, predictable margins, which benefit both our customers and the Company. As a result of our ratemaking efforts in recent years, Atmos Energy has:

- Formula rate mechanisms in place in four states that provide for an annual rate review and adjustment to rates.
- Infrastructure programs in place in all of our states that provide for an annual adjustment to rates for qualifying capital expenditures. Through our annual formula rate mechanisms and infrastructure programs, we have the ability to recover approximately 90 percent of our capital expenditures within six months and substantially all of our capital expenditures within twelve months.
- Authorization in tariffs, statute or commission rules that allows us to defer certain elements of our cost of service such as depreciation, ad valorem taxes and pension costs, until they are included in rates.
- WNA mechanisms in seven states that serve to minimize the effects of weather on approximately 96 percent of our distribution residential and commercial revenues.
- The ability to recover the gas cost portion of bad debts in five states which represents approximately 81 percent of our distribution residential and commercial revenues.

The following table provides a jurisdictional rate summary for our regulated operations as of September 30, 2022. This information is for regulatory purposes only and may not be representative of our actual financial position.

Division	Jurisdiction	Effective Date of Last Rate/ GRIP Action	Rate Base (thousands)(1)	Authorized Rate of Return(1)	Authorized Debt/ Equity Ratio(1)	Authorized Return on Equity(1)
Atmos Pipeline — Texas	Texas	05/18/2022	$3,432,180	8.87%	47/53	11.50%
Colorado-Kansas	Colorado	05/03/2018	134,726	7.55%	44/56	9.45%
	Colorado SSIR	01/01/2022	98,695	7.55%	44/56	9.45%
	Kansas	04/01/2020	242,314	7.03%	44/56	9.10%
	Kansas GSRS	02/01/2022	35,612	7.03%	44/56	9.10%
	Kansas SIP	04/01/2022	5,881	7.03%	44/56	9.10%
Kentucky/Mid-States	Kentucky	05/20/2022	568,506	6.82%	45/55	9.23%
	Kentucky-PRP	10/01/2020	39,368	7.49%	42/58	9.65%
	Tennessee	07/01/2022	447,448	7.53%	39/61	9.80%
	Virginia	04/01/2019	47,827	7.43%	42/58	9.20%
	Virginia-SAVE	10/01/2021	7,466	7.43%	42/58	9.20%
Louisiana	Louisiana	07/01/2022	942,422	7.30%	(4)	(4)
Mid-Tex	Mid-Tex Cities(6)	12/01/2021	4,394,489(5)	7.36%	42/58	9.80%
	Mid-Tex ATM Cities	06/10/2022	5,121,370(5)	7.97%	40/60	9.80%
	Mid-Tex Environs	06/10/2022	5,121,376(5)	7.97%	40/60	9.80%
	Mid-Tex — Dallas	05/25/2022	5,051,984(5)	7.41%	41/59	9.80%
Mississippi	Mississippi(7)	11/01/2021	473,932	7.81%	(4)	(4)
	Mississippi - SIR(7)	11/01/2021	323,695	7.81%	(4)	(4)
West Texas	West Texas Cities(8) (10)	12/01/2021	758,951(9)	7.36%	42/58	9.80%
	West Texas - ALDC	06/11/2022	857,631(9)	7.35%	41/59	(4)
	West Texas - Environs	06/11/2022	855,152(9)	7.97%	40/60	9.80%

Division	Jurisdiction	Bad Debt Rider(2)	Formula Rate	Infrastructure Mechanism	Performance Based Rate Program(3)	WNA Period
Atmos Pipeline — Texas	Texas	No	Yes	Yes	N/A	N/A
Colorado-Kansas	Colorado	No	No	Yes	No	N/A
	Kansas	Yes	No	Yes	Yes	October-May
Kentucky/Mid-States	Kentucky	Yes	No	Yes	Yes	November-April
	Tennessee	Yes	Yes	Yes	Yes	October-April
	Virginia	Yes	No	Yes	No	January-December
Louisiana	Louisiana	No	Yes	Yes	No	December-March
Mid-Tex Cities	Texas	Yes	Yes	Yes	No	November-April
Mid-Tex — Dallas	Texas	Yes	Yes	Yes	No	November-April
Mississippi	Mississippi	No	Yes	Yes	No	November-April
West Texas	Texas	Yes	Yes	Yes	No	October-May

(1) The rate base, authorized rate of return, authorized debt/equity ratio and authorized return on equity presented in this table are those from the most recent regulatory filing for each jurisdiction. These rate bases, rates of return, debt/equity ratios and returns on equity are not necessarily indicative of current or future rate bases, rates of return or returns on equity.
(2) The bad debt rider allows us to recover from customers the gas cost portion of customer accounts that have been written off.
(3) The performance-based rate program provides incentives to distribution companies to minimize purchased gas costs by allowing the companies and their customers to share the purchased gas costs savings.
(4) A rate base, rate of return, return on equity or debt/equity ratio was not included in the respective state commission's final decision.
(5) The Mid-Tex rate base represents a "system-wide," or 100 percent, of the Mid-Tex Division's rate base.
(6) The Mid-Tex Cities approved the Formula Rate Mechanism filing with rates effective October 1, 2022, which included a rate base of $5,235.0 million, an authorized return of 7.28%, a debt/equity ratio of 42/58 and an authorized ROE of 9.80%.
(7) The Mississippi Public Service Commission approved a settlement at its meeting on October 4, 2022, which included a rate base of $915.6 million and an authorized return of 7.53%. New rates were implemented November 1, 2022.
(8) The West Texas Cities includes all West Texas Division cities except Amarillo, Lubbock, Dalhart and Channing (ALDC).
(9) The West Texas rate base represents a "system-wide," or 100 percent, of the West Texas Division's rate base.
(10) The West Texas Cities approved the Formula Rate Mechanism filing with rates effective October 1, 2022, which included a rate base of $855.3 million, an authorized return of 7.28%, a debt/equity ratio of 42/58 and an authorized ROE of 9.80%.

Although substantial progress has been made in recent years to improve rate design and recovery of investment across our service areas, we are continuing to seek improvements in rate design to address cost variations and pursue tariffs that reduce regulatory lag associated with investments. Further, potential changes in federal energy policy, federal safety regulations and changing economic conditions will necessitate continued vigilance by the Company and our regulators in meeting the challenges presented by these external factors.

Recent Ratemaking Activity

The amounts described in the following sections represent the annual operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of the commission's or other governmental authority's final ruling. Our ratemaking outcomes include the refund (return) of excess deferred income taxes (EDIT) resulting from previously enacted tax reform legislation and do not reflect the true economic benefit of the outcomes because they do not include the corresponding income tax benefit. The following tables summarize the annualized ratemaking outcomes we implemented in each of the last three fiscal years.

Rate Action	Annual Increase (Decrease) in Operating Income	EDIT Impact	Annual Increase (Decrease) in Operating Income Excluding EDIT
		(In thousands)	
2022 Filings:			
Annual formula rate mechanisms	$ 169,354	$ 33,249	$ 202,603
Rate case filings	5,938	7,379	13,317
Other ratemaking activity	(370)	—	(370)
Total 2022 Filings	$ 174,922	$ 40,628	$ 215,550
2021 Filings:			
Annual formula rate mechanisms	$ 181,459	$ 39,306	$ 220,765
Rate case filings	5,119	1,168	6,287
Other ratemaking activity	(877)	—	(877)
Total 2021 Filings	$ 185,701	$ 40,474	$ 226,175
2020 Filings:			
Annual formula rate mechanisms	$ 160,857	$ —	$ 160,857
Rate case filings	(1,057)	—	(1,057)
Other ratemaking activity	353	—	353
Total 2020 Filings	$ 160,153	$ —	$ 160,153

The following ratemaking efforts seeking $144.5 million in annual operating income were initiated during fiscal 2022 but had not been completed or implemented as of September 30, 2022:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Colorado-Kansas	Rate Case	Colorado	$ 7,554
Colorado-Kansas	Rate Case	Kansas	7,989
Kentucky/Mid-States	Infrastructure Mechanism	Virginia (1)	477
Kentucky/Mid-States	Infrastructure Mechanism	Kentucky (2)	1,904
Mid-Tex	Formula Rate Mechanism	Mid-Tex Cities (3)	92,615
Mississippi	Infrastructure Mechanism	Mississippi (4)	10,006
Mississippi	Formula Rate Mechanism	Mississippi (4)	15,700
West Texas	Formula Rate Mechanism	West Texas Cities (5)	8,208
			$ 144,453

(1) On August 12, 2022, the State Corporation Commission of Virginia approved a rate increase of $0.5 million effective October 1, 2022.
(2) On August 12, 2022, the Kentucky Public Service Commission approved a rate increase of $1.9 million effective October 2, 2022, subject to refund.
(3) The Mid-Tex Cities approved a rate increase of $81.4 million, which includes $(0.4) million related to the return of excess deferred income taxes that will be offset by lower income tax expense. New rates were implemented on October 1, 2022.
(4) The Mississippi Public Service Commission (MPSC) approved an increase in operating income of $8.6 million for the SIR filing. The MPSC also approved an increase in operating income of $12.2 million for the SRF filing, which includes $0.8 million related to the refund of excess deferred income taxes that will be offset by lower income tax expense. New rates for both filings were implemented November 1, 2022.
(5) The West Texas Cities approved a rate increase of $7.3 million. New rates were implemented on October 1, 2022.

Our recent ratemaking activity is discussed in greater detail below.

Annual Formula Rate Mechanisms

As an instrument to reduce regulatory lag, formula rate mechanisms allow us to refresh our rates on an annual basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have specific infrastructure programs in all of our distribution divisions with tariffs in place to permit the investment associated with these programs to have their surcharge rate adjusted annually to recover approved capital costs incurred in a prior test-year period. The following table summarizes our annual formula rate mechanisms by state.

	Annual Formula Rate Mechanisms	
State	Infrastructure Programs	Formula Rate Mechanisms
Colorado	System Safety and Integrity Rider (SSIR)	—
Kansas	Gas System Reliability Surcharge (GSRS), System Integrity Program (SIP)	—
Kentucky	Pipeline Replacement Program (PRP)	—
Louisiana	(1)	Rate Stabilization Clause (RSC)
Mississippi	System Integrity Rider (SIR)	Stable Rate Filing (SRF)
Tennessee	(1)	Annual Rate Mechanism (ARM)
Texas	Gas Reliability Infrastructure Program (GRIP), (1)	Dallas Annual Rate Review (DARR), Rate Review Mechanism (RRM)
Virginia	Steps to Advance Virginia Energy (SAVE)	—

(1) Infrastructure mechanisms in Texas, Louisiana and Tennessee allow for the deferral of all expenses associated with capital expenditures incurred pursuant to these rules, which primarily consists of interest, depreciation and other taxes (Texas only), until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recoverable through base rates.

The following table summarizes our annual formula rate mechanisms with effective dates during the fiscal years ended September 30, 2022, 2021 and 2020:

Division	Jurisdiction	Test Year Ended	Increase (Decrease) in Annual Operating Income	EDIT Impact	Increase (Decrease) in Annual Operating Income Excluding EDIT	Effective Date
				(In thousands)		
2022 Filings:						
Kentucky/Mid-States	Tennessee ARM	09/2021	$ 2,466	$ —	$ 2,466	07/01/2022
Louisiana	Louisiana (1)	12/2021	17,650	(10,389)	7,261	07/01/2022
West Texas	Amarillo, Lubbock, Dalhart and Channing	12/2021	6,122	—	6,122	06/11/2022
West Texas	Triangle	12/2021	1,549	—	1,549	06/11/2022
West Texas	Environs	12/2021	1,221	—	1,221	06/11/2022
Mid-Tex	ATM Cities	12/2021	12,815	—	12,815	06/10/2022
Mid-Tex	Environs	12/2021	5,646	—	5,646	06/10/2022
Mid-Tex	DARR (2)	09/2021	13,201	—	13,201	05/25/2022
Atmos Pipeline - Texas	Texas	12/2021	78,750	—	78,750	05/18/2022
Colorado-Kansas	Kansas SIP	12/2021	623	—	623	04/01/2022
Colorado-Kansas	Kansas GSRS	09/2021	1,820	—	1,820	02/01/2022
Colorado-Kansas	Colorado SSIR	12/2022	2,610	—	2,610	01/01/2022
Mid-Tex	Mid-Tex Cities RRM	12/2020	21,673	33,851	55,524	12/01/2021
West Texas	West Texas Cities RRM	12/2020	151	3,347	3,498	12/01/2021
Mississippi	Mississippi - SIR	10/2022	8,354	2,123	10,477	11/01/2021
Mississippi	Mississippi - SRF	10/2022	(5,624)	4,317	(1,307)	11/01/2021
Kentucky/Mid-States	Virginia - SAVE	09/2022	327	—	327	10/01/2021
Total 2022 Filings			$ 169,354	$ 33,249	$ 202,603	
2021 Filings:						
Mid-Tex	Environs	12/2020	$ 4,632	$ —	$ 4,632	09/01/2021
Louisiana	Louisiana	12/2020	(2,407)	24,192	21,785	07/01/2021
Mid-Tex	ATM Cities (3)	12/2020	11,085	—	11,085	06/11/2021
West Texas	Triangle (3)	12/2020	416	—	416	06/11/2021
West Texas	Environs (3)	12/2020	1,267	—	1,267	06/11/2021
Mid-Tex	DARR (3)	09/2020	1,708	15,114	16,822	06/09/2021
Kentucky/Mid-States	Tennessee ARM	09/2020	10,260	—	10,260	06/01/2021
Atmos Pipeline - Texas	Texas	12/2020	43,868	—	43,868	05/11/2021
Colorado-Kansas	Kansas GSRS	09/2020	1,695	—	1,695	02/01/2021
Colorado-Kansas	Colorado SSIR	12/2021	2,366	—	2,366	01/01/2021
Mid-Tex	Mid-Tex Cities RRM	12/2019	82,645	—	82,645	12/01/2020
West Texas	West Texas Cities RRM	12/2019	5,645	—	5,645	12/01/2020
Mississippi	Mississippi - SIR	10/2021	10,556	—	10,556	11/01/2020
Mississippi	Mississippi - SRF	10/2021	5,856	—	5,856	11/01/2020
Kentucky/Mid-States	Virginia - SAVE	09/2021	305	—	305	10/01/2020
Kentucky/Mid-States	Kentucky PRP	09/2021	1,562	—	1,562	10/01/2020
Total 2021 Filings			$ 181,459	$ 39,306	$ 220,765	

2020 Filings:						
Mid-Tex	DARR	09/2019	$ 14,746	$ —	$ 14,746	09/01/2020
Louisiana	Louisiana	12/2019	14,781	—	14,781	07/01/2020
West Texas	Environs [4]	12/2019	1,031	—	1,031	06/16/2020
Kentucky/Mid-States	Tennessee ARM	05/2019	714	—	714	06/15/2020
Mid-Tex	ATM Cities [4]	12/2019	11,148	—	11,148	06/12/2020
Mid-Tex	Environs [4]	12/2019	4,440	—	4,440	05/20/2020
Atmos Pipeline - Texas	Texas	12/2019	49,251	—	49,251	05/20/2020
West Texas	Amarillo, Lubbock, Dalhart and Channing [4]	12/2019	5,937	—	5,937	04/28/2020
Colorado-Kansas	Colorado SSIR	12/2020	2,082	—	2,082	01/01/2020
Mississippi	Mississippi - SIR	10/2020	7,586	—	7,586	11/01/2019
Mississippi	Mississippi - SRF	10/2020	6,886	—	6,886	11/01/2019
Kentucky/Mid-States	Virginia - SAVE	09/2020	84	—	84	10/01/2019
Kentucky/Mid-States	Kentucky PRP	09/2020	2,912	—	2,912	10/01/2019
Mid-Tex	Mid-Tex RRM Cities	12/2018	34,380	—	34,380	10/01/2019
West Texas	West Texas Cities RRM	12/2018	4,879	—	4,879	10/01/2019
Total 2020 Filings			$ 160,857	$ —	$ 160,857	

(1) Rates were implemented on July 1, 2022, subject to refund.
(2) The rate increase for this filing was approved based on the effective date herein; however, the new rates were implemented beginning September 1, 2022.
(3) The rate increases for these filings were approved based on the effective dates herein; however, the new rates were implemented beginning September 1, 2021.
(4) The rate increases for our Texas GRIP filings were approved based on the effective date herein; however, the new rates were implemented beginning September 1, 2020.

Rate Case Filings

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company's costs as well as a reasonable rate of return to our shareholders and ensure that we continue to safely deliver reliable, reasonably priced natural gas service to our customers.

The following table summarizes our recent rate case activity during the fiscal years ended September 30, 2022, 2021 and 2020:

Division	State	Increase (Decrease) in Annual Operating Income	EDIT Impact	Increase (Decrease) in Annual Operating Income Excluding EDIT	Effective Date
			(In thousands)		
2022 Rate Case Filings:					
Kentucky/Mid-States	Kentucky [1]	$ 5,938	$ 7,379	$ 13,317	05/20/2022
Total 2022 Rate Case Filings		$ 5,938	$ 7,379	$ 13,317	
2021 Rate Case Filings:					
West Texas (ALDC)	Texas	$ 5,119	$ 1,168	$ 6,287	06/01/2021
Total 2021 Rate Case Filings		$ 5,119	$ 1,168	$ 6,287	
2020 Rate Case Filings:					
West Texas (Triangle)	Texas	$ (808)	$ —	$ (808)	04/21/2020
Colorado-Kansas	Kansas	(249)	—	(249)	04/01/2020
Total 2020 Rate Case Filings		$ (1,057)	$ —	$ (1,057)	

(1) The rate case outcome for Kentucky is inclusive of the fiscal 2022 pipeline replacement program.

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the fiscal years ended September 30, 2022, 2021 and 2020:

Division	Jurisdiction	Rate Activity	Increase (Decrease) in Annual Operating Income	Effective Date
			(In thousands)	
2022 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem (1)	$ (370)	02/01/2022
Total 2022 Other Rate Activity			$ (370)	
2021 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem (1)	$ (877)	02/01/2021
Total 2021 Other Rate Activity			$ (877)	
2020 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad-Valorem (1)	$ 353	02/01/2020
Total 2020 Other Rate Activity			$ 353	

(1) The Ad Valorem filing relates to property taxes that are either over or undercollected compared to the amount included in our Kansas service area's base rates.

Other Regulation

We are regulated by various state or local public utility authorities. We are also subject to regulation by the United States Department of Transportation with respect to safety requirements in the operation and maintenance of our transmission and distribution facilities. In addition, our operations are also subject to various state and federal laws regulating environmental matters. From time to time, we receive inquiries regarding various environmental matters. We believe that our properties and operations comply with, and are operated in conformity with, applicable safety and environmental statutes and regulations. There are no administrative or judicial proceedings arising under environmental quality statutes pending or known to be contemplated by governmental agencies which would have a material adverse effect on us or our operations. The Pipeline and Hazardous Materials Safety Administration (PHMSA), within the U.S. Department of Transportation, develops and enforces regulations for the safe, reliable and environmentally sound operation of the pipeline transportation system. The PHMSA pipeline safety statutes provide for states to assume safety authority over intrastate natural transmission and distribution gas pipelines. State pipeline safety programs are responsible for adopting and enforcing the federal and state pipeline safety regulations for intrastate natural gas transmission and distribution pipelines.

The Federal Energy Regulatory Commission (FERC) allows, pursuant to Section 311 of the Natural Gas Policy Act (NGPA), gas transportation services through our APT assets “on behalf of” interstate pipelines or local distribution companies served by interstate pipelines, without subjecting these assets to the jurisdiction of the FERC under the NGPA. Additionally, the FERC has regulatory authority over the use and release of interstate pipeline and storage capacity. The FERC also has authority to detect and prevent market manipulation and to enforce compliance with FERC’s other rules, policies and orders by companies engaged in the sale, purchase, transportation or storage of natural gas in interstate commerce. We have taken what we believe are the necessary and appropriate steps to comply with these regulations.

The SEC and the Commodities Futures Trading Commission, pursuant to the Dodd–Frank Act, established numerous regulations relating to U.S. financial markets. We enacted procedures and modified existing business practices and contractual arrangements to comply with such regulations. There are, however, some rulemaking proceedings that have not yet been finalized, including those relating to capital and margin rules for (non–cleared) swaps. We do not expect these rules to directly impact our business practices or collateral requirements. However, depending on the substance of these final rules, in addition to certain international regulatory requirements still under development that are similar to Dodd–Frank, our swap counterparties could be subject to additional and potentially significant capitalization requirements. These regulations could motivate counterparties to increase our collateral requirements or cash postings.

Competition

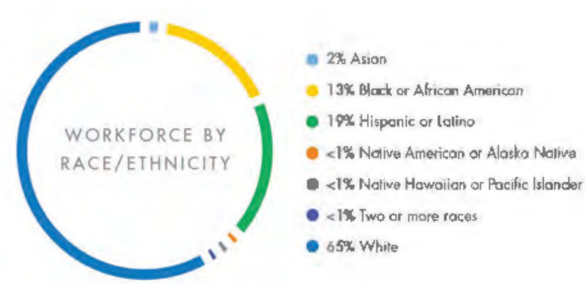
Although our regulated distribution operations are not currently in significant direct competition with any other distributors of natural gas to residential and commercial customers within our service areas, we do compete with other natural gas suppliers and suppliers of alternative fuels for sales to industrial customers. We compete in all aspects of our business with alternative energy sources, including, in particular, electricity. Electric utilities offer electricity as a rival energy source and compete for the space heating, water heating and cooking markets. Promotional incentives, improved equipment efficiencies and promotional rates all contribute to the acceptability of electrical equipment. The principal means to compete against alternative fuels is lower prices, and natural gas historically has maintained its price advantage in the residential, commercial and industrial markets.

Our pipeline and storage operations have historically faced competition from other existing intrastate pipelines seeking to provide or arrange transportation, storage and other services for customers. In the last few years, several new pipelines have been completed, which has increased the level of competition in this segment of our business.

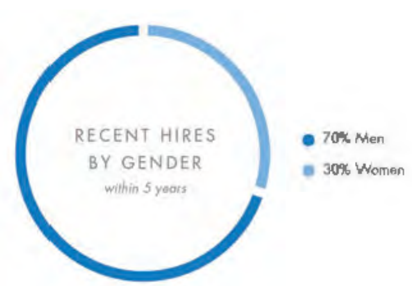
Employees

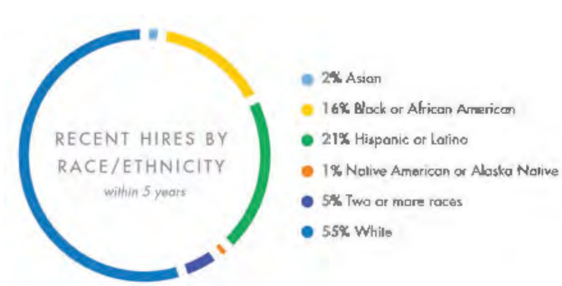
The Corporate Responsibility, Sustainability, and Safety Committee of the Board of Directors oversees matters relating to equal employment opportunities, diversity, and inclusion; human workplace rights; employee health and safety; and the Company's vision, values, and culture. It oversees the Company's policies, practices and procedures relating to sustainability to support the alignment of the Company's sustainability strategy with the Company's corporate strategy.

Part of our vision is to create a culture that respects and appreciates diversity. For this reason, we strive to have a workforce that reflects the communities we serve. At September 30, 2022, we had 4,791 employees, substantially unchanged from last year. We monitor our workforce data on a calendar year basis. As of December 31, 2021, 61 percent of our employees worked in field roles and 39 percent worked in support/shared services roles. No employees are subject to a collective bargaining agreement.



To recruit and hire individuals with a variety of skills, talents, backgrounds and experiences, we value and cultivate our strong relationships with hundreds of community and diversity outreach sources. We also target jobs fairs including those focused on minority, veteran and women candidates and partner with local colleges and universities to identify and recruit qualified applicants in each of the cities and towns we serve. Over the last five calendar years, we hired over 2,000 employees. Our culture is also reflected in our employee benefits. The physical, mental and financial health of our employees and their families is a top priority for the Company, which is why we have a strong, competitive benefits program to help employees and their families manage and protect their health, wealth and time.





We perform succession planning annually to ensure that we develop and sustain a strong bench of talent capable of performing at the highest levels. Not only is talent identified, but potential paths of development are discussed to ensure that employees have an opportunity to build their skills and are well-prepared for future roles. The strength of our succession planning process is evident through our long history of promoting our leaders from within the organization.

Available Information

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports, and amendments to those reports, and other forms that we file with or furnish to the Securities and Exchange Commission (SEC) at their website, *www.sec.gov*, are also available free of charge at our website, *www.atmosenergy.com/company/publications-and-sec-filings*, as soon as reasonably practicable, after we electronically file these reports with, or furnish these reports to, the SEC. We will also provide copies of these reports free of charge upon request to Shareholder Relations at the address and telephone number appearing below:

Shareholder Relations
Atmos Energy Corporation
P.O. Box 650205
Dallas, Texas 75265-0205
972-855-3729

Corporate Governance

In accordance with and pursuant to relevant related rules and regulations of the SEC as well as corporate governance-related listing standards of the New York Stock Exchange (NYSE), the Board of Directors of the Company has established and periodically updated our Corporate Governance Guidelines and Code of Conduct, which is applicable to all directors, officers and employees of the Company. In addition, in accordance with and pursuant to such NYSE listing standards, our Chief Executive Officer during fiscal 2022, John K. Akers, certified to the New York Stock Exchange that he was not aware of any violations by the Company of NYSE corporate governance listing standards. The Board of Directors also annually reviews and updates, if necessary, the charters for each of its Audit, Human Resources, Nominating and Corporate Governance and Corporate Responsibility, Sustainability and Safety Committees. All of the foregoing documents are posted on our website at *www.atmosenergy.com/company/corporate-responsiblity-reports*. We will also provide copies of all corporate governance documents free of charge upon request to Shareholder Relations at the address listed above.

ITEM 1A. ***Risk Factors.***

Our financial and operating results are subject to a number of risk factors, many of which are not within our control. Investors should carefully consider the following discussion of risk factors as well as other information appearing in this report. These factors include the following, which are organized by category:

Regulatory and Legislative Risks

We are subject to federal, state and local regulations that affect our operations and financial results.

We are subject to regulatory oversight from various federal, state and local regulatory authorities in the eight states that we serve. Therefore, our returns are continuously monitored and are subject to challenge for their reasonableness by the appropriate regulatory authorities or other third-party intervenors. In the normal course of business, as a regulated entity, we often need to place assets in service and establish historical test periods before rate cases that seek to adjust our allowed returns to recover that investment can be filed. Further, the regulatory review process can be lengthy in the context of traditional ratemaking. Because of this process, we suffer the negative financial effects of having placed assets in service without the benefit of rate relief, which is commonly referred to as "regulatory lag."

Regulatory authorities in the states we serve have approved various infrastructure and annual rate adjustment mechanisms to effectively reduce the regulatory lag inherent in the ratemaking process. Regulatory lag could significantly increase if the regulatory authorities modify or terminate these rate mechanisms. The regulatory process also involves the risk that regulatory authorities may (i) review our purchases of natural gas and adjust the amount of our gas costs that we pass through to our customers or (ii) limit or disallow the costs we may have incurred from our cost of service that can be recovered from customers.

We are also subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities relating to protection of the environment and health and safety matters, including those that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, the clean-up of contaminated sites, groundwater quality and availability, plant and wildlife protection, as well as work practices related to employee health and safety. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Failure to comply with these laws, regulations, permits and licenses may expose us to fines, penalties or interruptions in our operations that could be significant to our financial results. In addition, existing environmental regulations may be revised or our operations may become subject to new regulations.

Some of our operations are subject to increased federal regulatory oversight that could affect our operations and financial results.

FERC has regulatory authority over some of our operations, including the use and release of interstate pipeline and storage capacity. FERC has adopted rules designed to prevent market power abuse and market manipulation and to promote compliance with FERC's other rules, policies and orders by companies engaged in the sale, purchase, transportation or storage of natural gas in interstate commerce. These rules carry increased penalties for violations. Although we have taken steps to structure current and future transactions to comply with applicable current FERC regulations, changes in FERC regulations or their interpretation by FERC or additional regulations issued by FERC in the future could also adversely affect our business, financial condition or financial results.

We may experience increased federal, state and local regulation of the safety of our operations.

The safety and protection of the public, our customers and our employees is our top priority. We constantly monitor and maintain our pipeline and distribution systems to ensure that natural gas is delivered safely, reliably and efficiently through our network of more than 75,000 miles of distribution and transmission lines. As in recent years, natural gas distribution and pipeline companies are continuing to encounter increasing federal, state and local oversight of the safety of their operations. Although we believe these are costs ultimately recoverable through our rates, the costs of complying with new laws and regulations may have at least a short-term adverse impact on our operating costs and financial results.

Operational Risks

We may incur significant costs and liabilities resulting from pipeline integrity and other similar programs and related repairs.

PHMSA requires pipeline operators to develop integrity management programs to comprehensively evaluate certain areas along their pipelines and to take additional measures to protect pipeline segments located in “high consequence areas” where a leak or rupture could potentially do the most harm. As a pipeline operator, the Company is required to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a “high consequence area”;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventative and mitigating actions.

The Company incurs significant costs associated with its compliance with existing PHMSA and comparable state regulations. Although we believe these are costs ultimately recoverable through our rates, the costs of complying with new laws and regulations may have at least a short-term adverse impact on our operating costs and financial results. For example, the adoption of new regulations requiring more comprehensive or stringent safety standards could require installation of new or modified safety controls, new capital projects, or accelerated maintenance programs, all of which could require a potentially significant increase in operating costs.

Distributing, transporting and storing natural gas involve risks that may result in accidents and additional operating costs.

Our operations involve a number of hazards and operating risks inherent in storing and transporting natural gas that could affect the public safety and reliability of our distribution system. While Atmos Energy, with the support from each of its regulatory commissions, is accelerating the replacement of pipeline infrastructure, operating issues such as leaks, accidents, equipment problems and incidents, including explosions and fire, could result in legal liability, repair and remediation costs, increased operating costs, significant increased capital expenditures, regulatory fines and penalties and other costs and a loss of customer confidence. We maintain liability and property insurance coverage in place for many of these hazards and risks. However, because some of our transmission pipeline and storage facilities are near or are in populated areas, any loss of human life or adverse financial results resulting from such events could be large. If these events were not fully covered by our general liability and property insurance, which policies are subject to certain limits and deductibles, our operations or financial results could be adversely affected.

If contracted gas supplies, interstate pipeline and/or storage services are not available or delivered in a timely manner, our ability to meet our customers’ natural gas requirements may be impaired and our financial condition may be adversely affected.

In order to meet our customers’ annual and seasonal natural gas demands, we must obtain a sufficient supply of natural gas, interstate pipeline capacity and storage capacity. If we are unable to obtain these, either from our suppliers’ inability to deliver the contracted commodity or the inability to secure replacement quantities, our financial condition and results of operations may be adversely affected. If a substantial disruption to or reduction in interstate natural gas pipelines’ transmission and storage capacity occurred due to operational failures or disruptions, legislative or regulatory actions, hurricanes, tornadoes, floods, extreme cold weather, terrorist or cyber-attacks or acts of war, our operations or financial results could be adversely affected.

Our operations are subject to increased competition.

In residential and commercial customer markets, our distribution operations compete with other energy products, such as electricity and propane. Our primary product competition is with electricity for heating, water heating and cooking. Increases in the price of natural gas could negatively impact our competitive position by decreasing the price benefits of natural gas to the consumer. This could adversely impact our business if our customer growth slows or if our customers further conserve their use of gas, resulting in reduced gas purchases and customer billings.

In the case of industrial customers, such as manufacturing plants, adverse economic conditions, including higher gas costs, could cause these customers to use alternative sources of energy, such as electricity, or bypass our systems in favor of special competitive contracts with lower per-unit costs. Our pipeline and storage operations historically have faced limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. However, in the last few years, several new pipelines have been completed, which has increased the level of competition in this segment of our business.

Failure to attract and retain a qualified workforce could adversely affect our results of operations.

The competition for talent has become increasingly intense and we may experience increased employee turnover due to a tightening labor market. If we are unable to recruit and retain an appropriately qualified workforce, the Company could encounter operating challenges primarily due to a loss of institutional knowledge and expertise, errors due to inexperience, or the lengthy time period typically required to adequately train replacement personnel. In addition, higher costs could result from loss of productivity, increased safety compliance issues, or cost of contract labor.

Additionally, our ability to operate is contingent on maintaining a healthy workforce and a safe working environment. As a provider of essential services, we have an obligation to provide natural gas services to customers. Incidents of COVID-19 or any other future pandemic in our workforce could challenge the availability of our workforce which could threaten the continuity of our business operations.

Natural disasters, terrorist activities or other significant events could adversely affect our operations or financial results.

Natural disasters are always a threat to our assets and operations. In addition, the threat of terrorist activities could lead to increased economic instability and volatility in the price of natural gas that could affect our operations. Also, companies in our industry may face a heightened risk of exposure to actual acts of terrorism, which could subject our operations to increased risks. As a result, the availability of insurance covering such risks may become more limited, which could increase the risk that an event could adversely affect our operations or financial results.

Technology and Cybersecurity Risks

Increased dependence on technology may hinder the Company's business operations and adversely affect its financial condition and results of operations if such technologies fail.

Over the last several years, the Company has implemented or acquired a variety of technological tools including both Company-owned information technology and technological services provided by outside parties. These tools and systems support critical functions including scheduling and dispatching of service technicians, automated meter reading systems, customer care and billing, operational plant logistics, management reporting and external financial reporting. The failure of these or other similarly important technologies, or the Company's inability to have these technologies supported, updated, expanded, or integrated into other technologies, could hinder its business operations and adversely impact its financial condition and results of operations.

Although the Company has, when possible, developed alternative sources of technology and built redundancy into its computer networks and tools, there can be no assurance that these efforts would protect against all potential issues related to the loss of any such technologies.

Cyber-attacks or acts of cyber-terrorism could disrupt our business operations and information technology systems or result in the loss or exposure of confidential or sensitive customer, employee or Company information.

Our business operations and information technology systems may be vulnerable to an attack by individuals or organizations intending to disrupt our business operations and information technology systems, even though the Company has implemented policies, procedures and controls to prevent and detect these activities. We use our information technology systems to manage our distribution and intrastate pipeline and storage operations and other business processes. Disruption of those systems could adversely impact our ability to safely deliver natural gas to our customers, operate our pipeline and storage systems or serve our customers timely. Accordingly, if such an attack or act of terrorism were to occur, our operations and financial results could be adversely affected.

In addition, we use our information technology systems to protect confidential or sensitive customer, employee and Company information developed and maintained in the normal course of our business. Any attack on such systems that would result in the unauthorized release of customer, employee or other confidential or sensitive data could have a material adverse effect on our business reputation, increase our costs and expose us to additional material legal claims and liability. Even though we have insurance coverage in place for many of these cyber-related risks, if such an attack or act of terrorism were to occur, our operations and financial results could be adversely affected to the extent not fully covered by such insurance coverage.

Compliance with and changes in cybersecurity requirements have a cost and operational impact on our business, and failure to comply with such laws and regulations could adversely impact our reputation, results of operations, financial condition and/or cash flows.

As cyber-attacks are becoming more sophisticated, U.S. government warnings have indicated that critical infrastructure assets, including pipeline infrastructure, may be specifically targeted by certain groups. In 2021, the Transportation Security Administration (TSA) announced two new security directives in response to a ransomware attack on the Colonial Pipeline that occurred earlier in the year. These directives require critical pipeline owners to comply with mandatory reporting measures, designate a cybersecurity coordinator, provide vulnerability assessments, and ensure compliance with certain cybersecurity requirements. Such directives or other requirements may require expenditure of significant additional resources to respond to cyber-attacks, to continue to modify or enhance protective measures, or to assess, investigate and remediate any critical infrastructure security vulnerabilities. Any failure to comply with such government regulations or failure in our cybersecurity protective measures may result in enforcement actions that may have a material adverse effect on our business, results of operations and financial condition. In addition, there is no certainty that costs incurred related to securing against threats will be recovered through rates.

Climate Risks

Adverse weather conditions could affect our operations or financial results.

We have weather-normalized rates for approximately 96 percent of our residential and commercial revenues in our distribution operations, which substantially mitigates the adverse effects of warmer-than-normal weather for meters in those service areas. However, there is no assurance that we will continue to receive such regulatory protection from adverse weather in our rates in the future. The loss of such weather-normalized rates could have an adverse effect on our operations and financial results. In addition, our operating results may continue to vary somewhat with the actual temperatures during the winter heating season. Additionally, sustained cold weather could challenge our ability to adequately meet customer demand in our operations.

Greenhouse gas emissions or other legislation or regulations intended to address climate change could increase our operating costs, adversely affecting our financial results, growth, cash flows and results of operations.

Six of the eight states in which we operate have passed legislation to block attempts by local governments to limit the types of energy available to customers. However, federal, regional and/or state legislative and/or regulatory initiatives may attempt to control or limit the causes of climate change, including greenhouse gas emissions, such as carbon dioxide and methane. Such laws or regulations could impose costs tied to greenhouse gas emissions, operational requirements or restrictions, or additional charges to fund energy efficiency activities. They could also provide a cost advantage to alternative energy sources, impose costs or restrictions on end users of natural gas, or result in other costs or requirements, such as costs associated with the adoption of new infrastructure and technology to respond to new mandates. The focus on climate change could adversely impact the reputation of fossil fuel products or services. The occurrence of the foregoing events could put upward pressure on the cost of natural gas relative to other energy sources, increase our costs and the prices we charge to customers, reduce the demand for natural gas or cause fuel switching to other energy sources, and impact the competitive position of natural gas and the ability to serve new or existing customers, adversely affecting our business, results of operations and cash flows.

The operations and financial results of the Company could be adversely impacted as a result of climate change.

As climate change occurs, our businesses could be adversely impacted. To the extent climate change results in temperatures that differ materially from temperatures we are currently experiencing, financial results could be adversely affected through lower gas volumes and revenues. Climate change could also cause shifts in population, including customers moving away from our service territories.

It could also result in more frequent and more severe weather events, such as hurricanes and tornadoes, which could increase our costs to repair damaged facilities and restore service to our customers or impact the cost of gas. If we were unable to deliver natural gas to our customers, our financial results would be impacted by lost revenues, and we generally would have to seek approval from regulators to recover restoration costs. To the extent we would be unable to recover those costs, or if higher rates resulting from our recovery of such costs would result in reduced demand for our services, our future business, financial condition or financial results could be adversely impacted.

Financial, Economic and Market Risks

Our growth in the future may be limited by the nature of our business, which requires extensive capital spending.

Our operations are capital-intensive. We must make significant capital expenditures on a long-term basis to modernize our distribution and transmission system and to comply with the safety rules and regulations issued by the regulatory authorities responsible for the service areas we operate. In addition, we must continually build new capacity to serve the growing needs of the communities we serve. The magnitude of these expenditures may be affected by a number of factors, including new regulations, the general state of the economy and weather.

The liquidity required to fund our working capital, capital expenditures and other cash needs is provided from a combination of internally generated cash flows and external debt and equity financing. The cost and availability of borrowing funds from third party lenders or issuing equity is dependent on the liquidity of the credit markets, interest rates and other market conditions. This in turn may limit the amount of funds we can invest in our infrastructure.

The Company is dependent on continued access to the credit and capital markets to execute our business strategy.

Our long-term debt is currently rated as “investment grade” by Standard & Poor’s Corporation and Moody’s Investors Service, Inc. Similar to most companies, we rely upon access to both short-term and long-term credit and capital markets to satisfy our liquidity requirements. If adverse credit conditions were to cause a significant limitation on our access to the private credit and public capital markets, we could see a reduction in our liquidity. A significant reduction in our liquidity could in turn trigger a negative change in our ratings outlook or even a reduction in our credit ratings by one or more of the credit rating agencies. Such a downgrade could further limit our access to private credit and/or public capital markets and increase our costs of borrowing.

While we believe we can meet our capital requirements from our operations and the sources of financing available to us, we can provide no assurance that we will continue to be able to do so in the future, especially if the market price of natural gas increases significantly. The future effects on our business, liquidity and financial results of a deterioration of current conditions in the credit and capital markets could be material and adverse to us, both in the ways described above or in other ways that we do not currently anticipate.

We are exposed to market risks that are beyond our control, which could adversely affect our financial results.

We are subject to market risks beyond our control, including (i) commodity price volatility caused by market supply and demand dynamics, counterparty performance or counterparty creditworthiness and (ii) interest rate risk. We are generally insulated from commodity price risk through our purchased gas cost mechanisms. With respect to interest rate risk, increases in interest rates could adversely affect our future financial results to the extent that we do not recover our actual interest expense in our rates.

The concentration of our operations in the State of Texas exposes our operations and financial results to economic conditions, weather patterns and regulatory decisions in Texas.

Approximately 70 percent of our consolidated operations are located in the State of Texas. This concentration of our business in Texas means that our operations and financial results may be significantly affected by changes in the Texas economy in general, weather patterns and regulatory decisions by state and local regulatory authorities in Texas.

A deterioration in economic conditions could adversely affect our customers and negatively impact our financial results.

Any adverse changes in economic conditions in the states in which we operate could adversely affect the financial resources of many domestic households. As a result, our customers could seek to use less gas and it may be more difficult for them to pay their gas bills. This would likely lead to slower collections and higher than normal levels of accounts receivable. This, in turn, could increase our financing requirements. Additionally, should economic conditions deteriorate, our industrial customers could seek alternative energy sources, which could result in lower transportation volumes.

Increased gas costs could adversely impact our customer base and customer collections and increase our level of indebtedness.

Rapid increases in the costs of purchased gas would cause us to experience a significant increase in short-term or long-term debt. We must pay suppliers for gas when it is purchased, which can be significantly in advance of when these costs may be recovered through the collection of monthly customer bills for gas delivered. Increases in purchased gas costs also slow our natural gas distribution collections as customers are more likely to delay the payment of their gas bills, leading to higher than normal accounts receivable. This could result in higher short-term debt levels, greater collection efforts and increased bad debt expense.

The costs of providing health care benefits, pension and postretirement health care benefits and related funding requirements may increase substantially.

We provide health care benefits, a cash-balance pension plan and postretirement health care benefits to eligible full-time employees. The costs of providing health care benefits to our employees could significantly increase over time due to rapidly increasing health care inflation, and any future legislative changes related to the provision of health care benefits. The impact of additional costs which are likely to be passed on to the Company is difficult to measure at this time.

The costs of providing a cash-balance pension plan to eligible full-time employees prior to 2011 and postretirement health care benefits to eligible full-time employees and related funding requirements could be influenced by changes in the market value of the assets funding our pension and postretirement health care plans. Any significant declines in the value of these investments due to sustained declines in equity markets or a reduction in bond yields could increase the costs of our pension and postretirement health care plans and related funding requirements in the future. Further, our costs of providing such benefits and related funding requirements are also subject to a number of factors, including (i) changing demographics, including longer life expectancy of beneficiaries and an expected increase in the number of eligible former employees over the next five to ten years; (ii) various actuarial calculations and assumptions which may differ materially from actual results due primarily to changing market and economic conditions, including changes in interest rates, and higher or lower withdrawal rates; and (iii) future government regulation.

The costs to the Company of providing these benefits and related funding requirements could also increase materially in the future, should there be a material reduction in the amount of the recovery of these costs through our rates or should significant delays develop in the timing of the recovery of such costs, which could adversely affect our financial results.

ITEM 1B. *Unresolved Staff Comments.*

Not applicable.

ITEM 2. *Properties.*

Distribution, transmission and related assets

At September 30, 2022, in our distribution segment, we owned an aggregate of 73,243 miles of underground distribution and transmission mains throughout our distribution systems. These mains are located on easements or rights-of-way. We maintain our mains through a program of continuous inspection and repair and believe that our system of mains is in good condition. Through our pipeline and storage segment we also owned 5,652 miles of gas transmission lines.

Storage Assets

We own underground gas storage facilities in several states to supplement the supply of natural gas in periods of peak demand. The following table summarizes certain information regarding our underground gas storage facilities at September 30, 2022:

State	Usable Capacity (Mcf)	Cushion Gas (Mcf)(1)	Total Capacity (Mcf)	Maximum Daily Delivery Capability (Mcf)
Distribution Segment				
Kentucky	7,956,991	9,562,283	17,519,274	146,660
Kansas	3,239,000	2,300,000	5,539,000	32,000
Mississippi	1,907,571	2,442,917	4,350,488	29,136
Total	13,103,562	14,305,200	27,408,762	207,796
Pipeline and Storage Segment				
Texas	46,083,549	15,878,025	61,961,574	1,710,000
Louisiana	411,040	256,900	667,940	56,000
Total	46,494,589	16,134,925	62,629,514	1,766,000
Total	59,598,151	30,440,125	90,038,276	1,973,796

(1) Cushion gas represents the volume of gas that must be retained in a facility to maintain reservoir pressure.

Additionally, we contract for storage service in underground storage facilities on many of the interstate and intrastate pipelines serving us to supplement our proprietary storage capacity. The following table summarizes our contracted storage capacity at September 30, 2022:

Segment	Division/Company	Maximum Storage Quantity (MMBtu)	Maximum Daily Withdrawal Quantity (MDWQ)(1)
Distribution Segment			
	Colorado-Kansas Division	6,343,728	147,965
	Kentucky/Mid-States Division	8,175,103	226,320
	Louisiana Division	2,594,875	177,765
	Mid-Tex Division	6,000,000	230,000
	Mississippi Division	5,299,536	202,764
	West Texas Division	5,000,000	161,000
Total		33,413,242	1,145,814
Pipeline and Storage Segment			
	Trans Louisiana Gas Pipeline, Inc.	1,000,000	47,500
Total Contracted Storage Capacity		34,413,242	1,193,314

(1) Maximum daily withdrawal quantity (MDWQ) amounts will fluctuate depending upon the season and the month. Unless otherwise noted, MDWQ amounts represent the MDWQ amounts as of November 1, which is the beginning of the winter heating season.

ITEM 3. *Legal Proceedings.*

See Note 13 to the consolidated financial statements, which is incorporated in this Item 3 by reference.

ITEM 4. *Mine Safety Disclosures.*

Not applicable.

PART II

ITEM 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.*

Our stock trades on the New York Stock Exchange under the trading symbol "ATO." The dividends paid per share of our common stock for fiscal 2022 and 2021 are listed below.

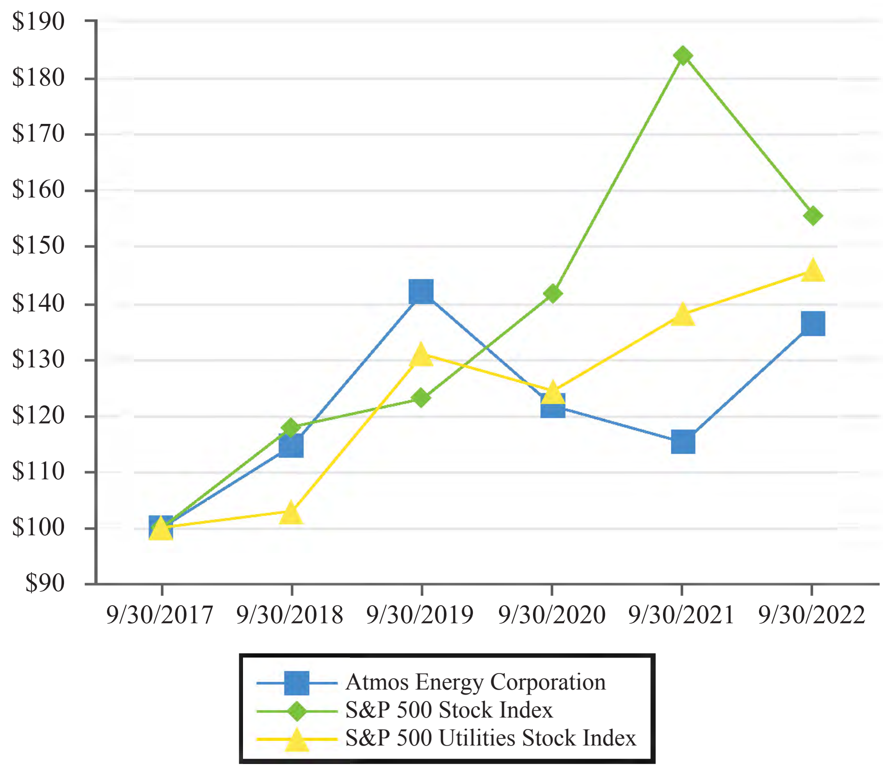
	Fiscal 2022	Fiscal 2021
Quarter ended:		
December 31	$ 0.680	$ 0.625
March 31	0.680	0.625
June 30	0.680	0.625
September 30	0.680	0.625
	$ 2.72	$ 2.50

Dividends are payable at the discretion of our Board of Directors out of legally available funds. The Board of Directors typically declares dividends in the same fiscal quarter in which they are paid. As of October 31, 2022, there were 10,052 holders of record of our common stock. Future payments of dividends, and the amounts of these dividends, will depend on our financial condition, results of operations, capital requirements and other factors. We sold no securities during fiscal 2022 that were not registered under the Securities Act of 1933, as amended.

Performance Graph

The performance graph and table below compares the yearly percentage change in our total return to shareholders for the last five fiscal years with the total return of the S&P 500 Stock Index (S&P 500) and the total return of the S&P 500 Utilities Industry Index. The graph and table below assume that $100.00 was invested on September 30, 2017 in our common stock, the S&P 500 and the S&P 500 Utilities Industry Index ax, as well as a reinvestment of dividends paid on such investments throughout the period.

Comparison of Five-Year Cumulative Total Return among Atmos Energy Corporation, S&P 500 Index and S&P 500 Utilities Industry Index



	Cumulative Total Return					
	9/30/2017	9/30/2018	9/30/2019	9/30/2020	9/30/2021	9/30/2022
Atmos Energy Corporation	100.00	114.53	141.78	121.61	115.14	136.38
S&P 500 Stock Index	100.00	117.91	122.93	141.55	184.02	155.55
S&P 500 Utilities Stock Index	100.00	102.93	130.82	124.32	138.01	145.71

The following table sets forth the number of securities authorized for issuance under our equity compensation plans at September 30, 2022.

	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders:			
1998 Long-Term Incentive Plan	696,744 (1)	$ —	874,481
Total equity compensation plans approved by security holders	696,744	—	874,481
Equity compensation plans not approved by security holders	—	—	—
Total	696,744	$ —	874,481

(1) Comprised of a total of 301,403 time-lapse restricted stock units, 195,184 director share units and 200,157 performance-based restricted stock units at the target level of performance granted under our 1998 Long-Term Incentive Plan.

ITEM 6. *Selected Financial Data.*

No disclosure required by Regulation S-K.

ITEM 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

INTRODUCTION

This section provides management's discussion of the financial condition, changes in financial condition and results of operations of Atmos Energy Corporation and its consolidated subsidiaries with specific information on results of operations and liquidity and capital resources. It includes management's interpretation of our financial results, the factors affecting these results, the major factors expected to affect future operating results and future investment and financing plans. This discussion should be read in conjunction with our consolidated financial statements and notes thereto.

Several factors exist that could influence our future financial performance, some of which are described in Item 1A above, "Risk Factors". They should be considered in connection with evaluating forward-looking statements contained in this report or otherwise made by or on behalf of us since these factors could cause actual results and conditions to differ materially from those set out in such forward-looking statements.

Cautionary Statement for the Purposes of the Safe Harbor under the Private Securities Litigation Reform Act of 1995

The statements contained in this Annual Report on Form 10-K may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: federal, state and local regulatory and political trends and decisions, including the impact of rate proceedings before various state regulatory commissions; increased federal regulatory oversight and potential penalties; possible increased federal, state and local regulation of the safety of our operations; possible significant costs and liabilities resulting from pipeline integrity and other similar programs and related repairs; the inherent hazards and risks involved in distributing, transporting and storing natural gas; the availability and accessibility of contracted gas supplies, interstate pipeline and/or storage services; increased competition from energy suppliers and alternative forms of energy; failure to attract and retain a qualified workforce; natural disasters, terrorist activities or other events and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control; increased dependence on technology that may hinder the Company's business if such technologies fail; the threat of cyber-attacks or acts of cyber-terrorism that could disrupt our business operations and information technology systems or result in the loss or exposure of confidential or sensitive customer, employee or Company information; the impact of new cybersecurity compliance requirements; adverse weather conditions; the impact of greenhouse gas emissions or other legislation or regulations intended to address climate change; the impact of climate change; the capital-intensive nature of our business; our ability to continue to access the credit and capital markets to execute our business strategy; market risks beyond our control affecting our risk management activities, including commodity price volatility, counterparty performance or creditworthiness and interest rate risk; the concentration of our operations in Texas; the impact of adverse economic conditions on our customers; changes in the availability and price of natural gas; and increased costs of providing health care benefits, along with pension and postretirement health care benefits and increased funding requirements. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

CRITICAL ACCOUNTING POLICIES

Our consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from estimates.

Our significant accounting policies are discussed in Note 2 to our consolidated financial statements. The accounting policies discussed below are both important to the presentation of our financial condition and results of operations and require management to make difficult, subjective or complex accounting estimates. Accordingly, these critical accounting policies are reviewed periodically by the Audit Committee of the Board of Directors.

Critical Accounting Policy	Summary of Policy	Factors Influencing Application of the Policy
Regulation	Our distribution and pipeline operations meet the criteria of a cost-based, rate-regulated entity under accounting principles generally accepted in the United States. Accordingly, the financial results for these operations reflect the effects of the ratemaking and accounting practices and policies of the various regulatory commissions to which we are subject. As a result, certain costs that would normally be expensed under accounting principles generally accepted in the United States are permitted to be capitalized or deferred on the balance sheet because it is probable they can be recovered through rates. Further, regulation may impact the period in which revenues or expenses are recognized. The amounts expected to be recovered or recognized are based upon historical experience and our understanding of the regulations. Discontinuing the application of this method of accounting for regulatory assets and liabilities or changes in the accounting for our various regulatory mechanisms could significantly increase our operating expenses as fewer costs would likely be capitalized or deferred on the balance sheet, which could reduce our net income.	Decisions of regulatory authorities Issuance of new regulations or regulatory mechanisms Assessing the probability of the recoverability of deferred costs Continuing to meet the criteria of a cost-based, rate regulated entity for accounting purposes
Unbilled Revenue	We follow the revenue accrual method of accounting for distribution segment revenues whereby revenues attributable to gas delivered to customers, but not yet billed under the cycle billing method, are estimated and accrued and the related costs are charged to expense. When permitted, we implement rates that have not been formally approved by our regulatory authorities, subject to refund.We recognize this revenue and establish a reserve for amounts that could be refunded based on our experience for the jurisdiction in which the rates were implemented.	Estimates of delivered sales volumes based on actual tariff information and weather information and estimates of customer consumption and/or behavior Estimates of purchased gas costs related to estimated deliveries Estimates of amounts billed subject to refund

Critical Accounting Policy	Summary of Policy	Factors Influencing Application of the Policy
Pension and other postretirement plans	Pension and other postretirement plan costs and liabilities are determined on an actuarial basis using a September 30 measurement date and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities. The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligations and net periodic pension and postretirement benefit plan costs. When establishing our discount rate, we consider high quality corporate bond rates based on bonds available in the marketplace that are suitable for settling the obligations, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with currently available high quality corporate bonds. The expected long-term rate of return on assets is utilized in calculating the expected return on plan assets component of our annual pension and postretirement plan costs. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater than or less than the assumed rate, that year's annual pension or postretirement plan costs are not affected. Rather, this gain or loss reduces or increases future pension or postretirement plan costs over a period of approximately ten to twelve years. The market-related value of our plan assets represents the fair market value of the plan assets, adjusted to smooth out short-term market fluctuations over a five-year period. The use of this methodology will delay the impact of current market fluctuations on the pension expense for the period. We estimate the assumed health care cost trend rate used in determining our postretirement net expense based upon our actual health care cost experience, the effects of recently enacted legislation and general economic conditions. Our assumed rate of retirement is estimated based upon our annual review of our participant census information as of the measurement date.	General economic and market conditions Assumed investment returns by asset class Assumed future salary increases Assumed discount rate Projected timing of future cash disbursements Health care cost experience trends Participant demographic information Actuarial mortality assumptions Impact of legislation Impact of regulation
Impairment assessments	We review the carrying value of our long-lived assets, including goodwill and identifiable intangibles, whenever events or changes in circumstance indicate that such carrying values may not be recoverable, and at least annually for goodwill, as required by U.S. accounting standards. The evaluation of our goodwill balances and other long-lived assets or identifiable assets for which uncertainty exists regarding the recoverability of the carrying value of such assets involves the assessment of future cash flows and external market conditions and other subjective factors that could impact the estimation of future cash flows including, but not limited to the commodity prices, the amount and timing of future cash flows, future growth rates and the discount rate. Unforeseen events and changes in circumstances or market conditions could adversely affect these estimates, which could result in an impairment charge.	General economic and market conditions Projected timing and amount of future discounted cash flows Judgment in the evaluation of relevant data

Non-GAAP Financial Measures

As described further in Note 14 to the consolidated financial statements, due to the passage of Kansas House Bill 2585, we remeasured our deferred tax liability and updated our state deferred tax rate. As a result, we recorded a non-cash income tax benefit of $21.0 million for the fiscal year ended September 30, 2020. Due to the non-recurring nature of this benefit, we believe that net income and diluted net income per share before the non-cash income tax benefit provide a more relevant measure to analyze our financial performance than net income and diluted net income per share in order to allow investors to better analyze our core results and allow the information to be presented on a comparative basis. Accordingly, the following discussion and analysis of our financial performance will reference adjusted net income and adjusted diluted earnings per share, non-GAAP measures, which are calculated as follows:

	For the Fiscal Year Ended September 30				
	2022	2021	2020	2022 vs. 2021	2021 vs. 2020
	(In thousands, except per share data)				
Net income	$ 774,398	$ 665,563	$ 601,443	$ 108,835	$ 64,120
Non-cash income tax benefits	—	—	(20,962)	—	20,962
Adjusted net income	$ 774,398	$ 665,563	$ 580,481	$ 108,835	$ 85,082
Diluted net income per share	$ 5.60	$ 5.12	$ 4.89	$ 0.48	$ 0.23
Diluted EPS from non-cash income tax benefits	—	—	(0.17)	—	0.17
Adjusted diluted net income per share	$ 5.60	$ 5.12	$ 4.72	$ 0.48	$ 0.40

RESULTS OF OPERATIONS

Overview

Atmos Energy strives to operate its businesses safely and reliably while delivering superior shareholder value. Our commitment to modernizing our natural gas distribution and transmission systems requires a significant level of capital spending. We have the ability to begin recovering a significant portion of these investments timely through rate designs and mechanisms that reduce or eliminate regulatory lag and separate the recovery of our approved rate from customer usage patterns. The execution of our capital spending program, the ability to recover these investments timely and our ability to access the capital markets to satisfy our financing needs are the primary drivers that affect our financial performance.

The following table details our consolidated net income by segment during the last three fiscal years:

	For the Fiscal Year Ended September 30		
	2022	2021	2020
	(In thousands)		
Distribution segment	$ 521,977	$ 445,862	$ 395,664
Pipeline and storage segment	252,421	219,701	205,779
Net income	$ 774,398	$ 665,563	$ 601,443

During fiscal 2022, we recorded net income of $774.4 million, or $5.60 per diluted share, compared to net income of $665.6 million, or $5.12 per diluted share in the prior year. The year-over-year increase in net income of $108.8 million largely reflects positive rate outcomes driven by safety and reliability spending and distribution customer growth, partially offset by an increase in employee related costs, increased spending on system maintenance activities and an increase in depreciation expense and property taxes associated with increased capital investments.

During the year ended September 30, 2022, we implemented ratemaking regulatory actions which resulted in an increase in annual operating income of $174.9 million. Excluding the impact of the refund of excess deferred income taxes resulting from previously enacted tax reform legislation, our total fiscal 2022 rate outcomes were $215.6 million. Additionally, we had ratemaking efforts in progress at September 30, 2022, seeking a total increase in annual operating income of $144.5 million.

During fiscal year 2022, we refunded $167.8 million in excess deferred tax liabilities to customers. The refunds reduced operating income and reduced our annual effective income tax rate to 9.1% in fiscal 2022 compared with 18.8% in fiscal 2021.

Capital expenditures for fiscal 2022 were $2.4 billion. Over 85 percent was invested to improve the safety and reliability of our distribution and transportation systems, with a significant portion of this investment incurred under regulatory mechanisms that reduce regulatory lag to six months or less.

During fiscal 2022, we completed approximately $1.6 billion of long-term debt and equity financing. As of September 30, 2022, our equity capitalization was 53.6 percent. Excluding the $2.2 billion of incremental financing issued in conjunction with Winter Storm Uri, our equity capitalization was 61.3 percent. As of September 30, 2022, we had approximately $3.1 billion in total liquidity, consisting of $51.6 million in cash and cash equivalents, $776.6 million in funds available through equity forward sales agreements and $2,309.4 million in undrawn capacity under our credit facilities.

As a result of the continued stability of our earnings, cash flows and capital structure, our Board of Directors increased the quarterly dividend by 8.8% percent for fiscal 2023.

Distribution Segment

The distribution segment is primarily comprised of our regulated natural gas distribution and related sales operations in eight states. The primary factors that impact the results of our distribution operations are our ability to earn our authorized rates of return, competitive factors in the energy industry and economic conditions in our service areas.

Our ability to earn our authorized rates is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions to minimize regulatory lag and, ultimately, separate the recovery of our approved rates from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions. The “Ratemaking Activity” section of this Form 10-K describes our current rate strategy, progress towards implementing that strategy and recent ratemaking initiatives in more detail. During fiscal 2022, we completed regulatory proceedings in our distribution segment resulting in a $96.2 million increase in annual operating income. Excluding the impact of the refund of excess deferred income taxes resulting from previously enacted tax reform legislation, our total fiscal 2022 annualized rate outcomes in our distribution segment were $136.8 million.

Our distribution operations are also affected by the cost of natural gas. We are generally able to pass the cost of gas through to our customers without markup under purchased gas cost adjustment mechanisms; therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Revenues in our Texas and Mississippi service areas include franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income.

The cost of gas typically does not have a direct impact on our operating income because these costs are recovered through our purchased gas cost adjustment mechanisms. However, higher gas costs may adversely impact our accounts receivable collections, resulting in higher bad debt expense. This risk is currently mitigated by rate design that allows us to collect from our customers the gas cost portion of our bad debt expense on approximately 81 percent of our residential and commercial revenues. Additionally, higher gas costs may require us to increase borrowings under our credit facilities, resulting in higher interest expense. Finally, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or, in the case of industrial consumers, to use alternative energy sources.

Review of Financial and Operating Results

Financial and operational highlights for our distribution segment for the fiscal years ended September 30, 2022, 2021 and 2020 are presented below.

	For the Fiscal Year Ended September 30				
	2022	2021	2020	2022 vs. 2021	2021 vs. 2020
	(In thousands, unless otherwise noted)				
Operating revenues	$ 4,035,194	$ 3,241,973	$ 2,626,993	$ 793,221	$ 614,980
Purchased gas cost	2,210,302	1,501,695	1,071,227	708,607	430,468
Operating expenses	1,220,347	1,121,764	1,027,523	98,583	94,241
Operating income	604,545	618,514	528,243	(13,969)	90,271
Other non-operating income (expense)	6,946	(20,694)	(1,265)	27,640	(19,429)
Interest charges	49,921	36,629	39,634	13,292	(3,005)
Income before income taxes	561,570	561,191	487,344	379	73,847
Income tax expense	39,593	115,329	105,147	(75,736)	10,182
Non-cash income tax benefit [1]	—	—	(13,467)	—	13,467
Net income	$ 521,977	$ 445,862	$ 395,664	$ 76,115	$ 50,198
Consolidated distribution sales volumes — MMcf	292,266	308,833	291,650	(16,567)	17,183
Consolidated distribution transportation volumes — MMcf	152,709	152,513	147,387	196	5,126
Total consolidated distribution throughput — MMcf	444,975	461,346	439,037	(16,371)	22,309
Consolidated distribution average cost of gas per Mcf sold	$ 7.56	$ 4.86	$ 3.67	$ 2.70	$ 1.19

(1) See Note 14 to the consolidated financial statements for further information.

Fiscal year ended September 30, 2022 compared with fiscal year ended September 30, 2021

Operating income for our distribution segment decreased two percent. Increased refunds of excess deferred taxes to customers decreased year-over-year operating income $98.5 million and reduced the effective income tax rate for this segment to 7.1% compared to 20.6% in the prior year. Additional key drivers for the change in operating income include:

- a $149.9 million increase in rate adjustments, primarily in our Mid-Tex, West Texas and Louisiana Divisions.
- a $15.2 million increase due to an increase in the number of customers served, primarily in our Mid-Tex Division.
- a $24.9 million decrease in bad debt expense, primarily due to the resumption of collection activities in late fiscal 2021 following the expiration of pandemic-related collection moratoriums.

Partially offset by:

- a $50.4 million increase in depreciation expense and property taxes associated with increased capital investments.
- a $17.3 million decrease in consumption, net of WNA, primarily due to the decline in residential consumption during the second fiscal quarter.
- an $8.8 million increase in system maintenance and related activities.
- a $25.5 million increase in employee related costs driven by increased headcount, increased number of service orders performed and higher benefits costs.
- an $8.9 million increase in insurance premiums.

The year-over-year change in other non-operating income (expense) of $27.6 million primarily reflects lower non-service costs related to our postretirement medical plan, partially offset by an increase in unrealized losses on equity investments. Interest charges increased $13.3 million due to the issuance of long-term debt during fiscal 2022 and interest expense recognized in fiscal 2022 related to debt incurred as a result of Winter Storm Uri. As described in Note 9 to the consolidated financial statements, interest related to the incremental financing incurred as a result of Winter Storm Uri was deferred through December 31, 2021 pursuant to a regulatory order issued by the State of Texas.

The fiscal year ended September 30, 2021 compared with fiscal year ended September 30, 2020 for our distribution segment is described in Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" of our Annual Report on Form 10-K for the fiscal year ended September 30, 2021.

The following table shows our operating income by distribution division, in order of total rate base, for the fiscal years ended September 30, 2022, 2021 and 2020. The presentation of our distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	For the Fiscal Year Ended September 30				
	2022	2021	2020	2022 vs. 2021	2021 vs. 2020
			(In thousands)		
Mid-Tex	$ 315,644	$ 310,293	$ 236,066	$ 5,351	$ 74,227
Kentucky/Mid-States	84,098	73,259	76,745	10,839	(3,486)
Louisiana	73,486	72,388	71,892	1,098	496
West Texas	53,604	51,104	52,493	2,500	(1,389)
Mississippi	65,947	65,337	55,938	610	9,399
Colorado-Kansas	26,000	32,778	34,039	(6,778)	(1,261)
Other	(14,234)	13,355	1,070	(27,589)	12,285
Total	$ 604,545	$ 618,514	$ 528,243	$ (13,969)	$ 90,271

Pipeline and Storage Segment

Our pipeline and storage segment consists of the pipeline and storage operations of our Atmos Pipeline–Texas Division (APT) and our natural gas transmission operations in Louisiana. APT is one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Barnett Shale, the Texas Gulf Coast and the Permian Basin of West Texas. APT provides transportation and storage services to our Mid-Tex Division, other third-party local distribution companies, industrial and electric generation customers, as well as marketers and producers. Over 80 percent of this segment's revenues are derived from these services. As part of its pipeline operations, APT owns and operates five underground storage facilities in Texas.

Our natural gas transmission operations in Louisiana are comprised of a 21-mile pipeline located in the New Orleans, Louisiana area that is primarily used to aggregate gas supply for our distribution division in Louisiana under a long-term contract and, on a more limited basis, to third parties. The demand fee charged to our Louisiana distribution division for these services is subject to regulatory approval by the Louisiana Public Service Commission. We also manage two asset management plans, which have been approved by applicable state regulatory commissions. Generally, these asset management plans require us to share with our distribution customers a significant portion of the cost savings earned from these arrangements.

Our pipeline and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our Texas and Louisiana service areas. Natural gas prices do not directly impact the results of this segment as revenues are derived from the transportation and storage of natural gas. However, natural gas prices and demand for natural gas could influence the level of drilling activity in the supply areas that we serve, which may influence the level of throughput we may be able to transport on our pipelines. Further, natural gas price differences between the various hubs that we serve in Texas could influence the volumes of gas transported for shippers through our Texas pipeline system and rates for such transportation.

The results of APT are also significantly impacted by the natural gas requirements of its local distribution company customers. Additionally, its operations may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

APT annually uses GRIP to recover capital costs incurred in the prior calendar year. On February 11, 2022, APT made a GRIP filing that covered changes in net property, plant and equipment investment from January 1, 2021 through December 31, 2021 with a requested increase in operating income of $78.8 million. On May 18, 2022, the Texas Railroad Commission approved the Company's GRIP filing.

The demand fee our Louisiana natural gas transmission pipeline charges to our Louisiana distribution division increases five percent annually and has been approved by the Louisiana Public Service Commission until September 30, 2027.

Review of Financial and Operating Results

Financial and operational highlights for our pipeline and storage segment for the fiscal years ended September 30, 2022, 2021 and 2020 are presented below.

	For the Fiscal Year Ended September 30				
	2022	2021	2020	2022 vs. 2021	2021 vs. 2020
	(In thousands, unless otherwise noted)				
Mid-Tex / Affiliate transportation revenue	$ 546,038	$ 497,730	$ 474,077	$ 48,308	$ 23,653
Third-party transportation revenue	136,907	127,874	127,444	9,033	430
Other revenue	10,715	11,743	7,818	(1,028)	3,925
Total operating revenues	693,660	637,347	609,339	56,313	28,008
Total purchased gas cost	(1,583)	1,582	1,548	(3,165)	34
Operating expenses	378,806	349,281	311,935	29,525	37,346
Operating income	316,437	286,484	295,856	29,953	(9,372)
Other non-operating income	26,791	18,549	8,436	8,242	10,113
Interest charges	52,890	46,925	44,840	5,965	2,085
Income before income taxes	290,338	258,108	259,452	32,230	(1,344)
Income tax expense	37,917	38,407	61,168	(490)	(22,761)
Non-cash income tax benefit [(1)]	—	—	(7,495)	—	7,495
Net income	$ 252,421	$ 219,701	$ 205,779	$ 32,720	$ 13,922
Gross pipeline transportation volumes — MMcf	776,608	799,724	822,499	(23,116)	(22,775)
Consolidated pipeline transportation volumes — MMcf	580,488	585,857	621,371	(5,369)	(35,514)

(1) See Note 14 to the consolidated financial statements for further information.

Fiscal year ended September 30, 2022 compared with fiscal year ended September 30, 2021

Operating income for our pipeline and storage segment increased 10 percent. Increased refunds of excess deferred taxes to customers decreased year-over-year operating income by $13.3 million and reduced the effective income tax rate for this segment to 13.1% compared to 14.9% in the prior year. Additional drivers for the change in operating income include:

- a $70.4 million increase due to rate adjustments from GRIP filings approved in May 2021 and 2022. The increase in rates was driven by increased safety and reliability spending.

Partially offset by:

- an $8.4 million increase in system maintenance expense primarily due to spending on hydrostatic testing.
- a $15.4 million increase in depreciation expense and property taxes associated with increased capital investments.

The year-over-year change in other non-operating income and interest charges of $2.3 million reflects increased allowance for funds used during construction (AFUDC) primarily due to increased capital spending, partially offset by an increase in interest expense due to the issuance of long-term debt during fiscal 2022.

The fiscal year ended September 30, 2021 compared with fiscal year ended September 30, 2020 for our pipeline and storage segment is described in Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" of our Annual Report on Form 10-K for the fiscal year ended September 30, 2021.

INFLATION REDUCTION ACT OF 2022

In August 2022, the U.S. government enacted the Inflation Reduction Act of 2022 (the Inflation Reduction Act) into law. The Inflation Reduction Act includes a new corporate alternative minimum tax (the Corporate AMT) of 15% on the adjusted financial statement income (AFSI) of corporations with average AFSI exceeding $1.0 billion over a three-year period. We currently anticipate this tax will apply to us within the next four to five years. The impact on our financial position, results of operations and cash flows is dependent on future guidance from the U.S. government. Also, the Inflation Reduction Act imposes a methane emissions charge for methane emissions in excess of 25,000 metric tons carbon dioxide equivalent per year. Based on our preliminary evaluation of the regulations, we currently do not anticipate this provision of the Inflation Reduction Act will have a material impact on our financial position, results of operations or cash flows. Additionally, the Inflation

Reduction Act imposes an excise tax of 1% tax on the fair market value of net stock repurchases made after December 31, 2022. The impact of this provision will be dependent on the extent of share repurchases made in future periods.

LIQUIDITY AND CAPITAL RESOURCES

The liquidity required to fund our working capital, capital expenditures and other cash needs is provided from a combination of internally generated cash flows and external debt and equity financing. Additionally, we have a $1.5 billion commercial paper program and four committed revolving credit facilities with $2.5 billion in total availability from third-party lenders. The commercial paper program and credit facilities provide cost-effective, short-term financing until it can be replaced with a balance of long-term debt and equity financing that achieves the Company's desired capital structure with an equity-to-total-capitalization ratio between 50% and 60%, inclusive of long-term and short-term debt. Additionally, we have various uncommitted trade credit lines with our gas suppliers that we utilize to purchase natural gas on a monthly basis.

We have a shelf registration statement on file with the Securities and Exchange Commission (SEC) that allows us to issue up to $5.0 billion in common stock and/or debt securities. As of the date of this report, approximately $1.4 billion of securities remained available for issuance under the shelf registration statement, which expires June 29, 2024.

We also have an at-the-market (ATM) equity sales program that allows us to issue and sell shares of our common stock up to an aggregate offering price of $1.0 billion (including shares of common stock that may be sold pursuant to forward sale agreements entered into in connection with the ATM equity sales program), which expires June 29, 2024. At September 30, 2022, approximately $481.7 million of equity is available for issuance under this ATM equity sales program. Additionally, as of September 30, 2022, we had $776.6 million in available proceeds from outstanding forward sale agreements.

On September 27, 2022, we settled $500 million of forward starting interest rate swaps associated with a planned debt issuance that was completed on October 3, 2022. The following table summarizes our existing forward starting interest rate swaps as of September 30, 2022.

Planned Debt Issuance Date	Amount Hedged	Effective Interest Rate
	(In thousands)	
Fiscal 2024	$ 450,000	1.80 %
Fiscal 2025	600,000	1.75 %
Fiscal 2026	300,000	2.16 %
	$ 1,350,000	

The liquidity provided by these sources is expected to be sufficient to fund the Company's working capital needs and capital expenditures program. Additionally, we expect to continue to be able to obtain financing upon reasonable terms as necessary.

The following table presents our capitalization as of September 30, 2022 and 2021:

	September 30			
	2022		2021	
	(In thousands, except percentages)			
Short-term debt	$ 184,967	1.1 %	$ —	— %
Long-term debt [(1)]	7,962,104	45.3 %	7,330,657	48.1 %
Shareholders' equity [(2)]	9,419,091	53.6 %	7,906,889	51.9 %
Total capitalization, including short-term debt	$ 17,566,162	100.0 %	$ 15,237,546	100.0 %

(1) Inclusive of our finance leases.
(2) Excluding the $2.2 billion of incremental financing issued to pay for the purchased gas costs incurred during Winter Storm Uri, our equity capitalization ratio would have been 61.3% and 60.6% at September 30, 2022 and 2021.

Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These factors include regulatory changes, the price for our services, the demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks and other factors.

Cash flows from operating, investing and financing activities for the years ended September 30, 2022, 2021 and 2020 are presented below.

	For the Fiscal Year Ended September 30				
	2022	2021	2020	2022 vs. 2021	2021 vs. 2020
			(In thousands)		
Total cash provided by (used in)					
Operating activities	$ 977,584	$ (1,084,251)	$ 1,037,999	$ 2,061,835	$ (2,122,250)
Investing activities	(2,429,958)	(1,963,655)	(1,925,518)	(466,303)	(38,137)
Financing activities	1,387,205	3,143,821	883,777	(1,756,616)	2,260,044
Change in cash and cash equivalents	(65,169)	95,915	(3,742)	(161,084)	99,657
Cash and cash equivalents at beginning of period	116,723	20,808	24,550	95,915	(3,742)
Cash and cash equivalents at end of period	$ 51,554	$ 116,723	$ 20,808	$ (65,169)	$ 95,915

Cash flows for the fiscal year ended September 30, 2021 compared with fiscal year ended September 30, 2020 is described in Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" of our Annual Report on Form 10-K for the fiscal year ended September 30, 2021.

Cash flows from operating activities

For the fiscal year ended September 30, 2022, cash flow provided by operating activities was $977.6 million compared with cash flow used in operating activities of $1.1 billion in the prior year. Fiscal 2021 operating cash flow included $2.1 billion of cash paid for gas costs incurred during Winter Storm Uri. Excluding this cash outflow, operating cash flow in fiscal 2021 was $996.1 million. The year-over-year decrease in operating cash flow reflects the refund of excess deferred tax liabilities, increased purchases of gas stored underground and the timing of gas cost recoveries, partially offset by increased customer collections and the positive effects of successful rate case outcomes achieved in fiscal 2021 and 2022.

Cash flows from investing activities

Our capital expenditures are primarily used to improve the safety and reliability of our distribution and transmission system through pipeline replacement and system modernization and to enhance and expand our system to meet customer needs. Over the last three fiscal years, approximately 88 percent of our capital spending has been committed to improving the safety and reliability of our system.

For the fiscal year ended September 30, 2022, we had $2.4 billion in capital expenditures compared with $2.0 billion for the fiscal year ended September 30, 2021. Capital spending increased by $474.9 million, or 24 percent, as a result of planned increases to modernize our system.

Cash flows from financing activities

Our financing activities provided $1.4 billion and $3.1 billion in cash for fiscal years 2022 and 2021.

During the fiscal year ended September 30, 2022, we received $1.6 billion in net proceeds from the issuance of long-term debt and equity. We completed a public offering of $600 million of 2.85% senior notes due 2052. We also completed a public offering of $200 million of 2.625% senior notes due 2029 that were used to repay our $200 million floating-rate term loan. Additionally, during the year ended September 30, 2022, we settled 7,907,833 shares that had been sold on a forward basis for net proceeds of $776.8 million. The net proceeds were used primarily to support capital spending and for other general corporate purposes. We also received $197.1 million from the settlement of forward starting interest rate swaps related to a debt issuance completed in October 2022. Additionally, cash dividends increased due to an 8.8 percent increase in our dividend rate and an increase in shares outstanding.

During the fiscal year ended September 30, 2021, we received $3.4 billion in net proceeds from the issuance of long-term debt and equity. We completed a public offering of $600 million of 1.50% senior notes due 2031, $1.1 billion of 0.625% senior notes due 2023 and $1.1 billion floating rate senior notes due 2023. Net proceeds from the latter two notes were used to pay for gas costs incurred during Winter Storm Uri. Additionally, during the year ended September 30, 2021, we settled 6,130,875 shares that had been sold on a forward basis for net proceeds of $606.7 million. The net proceeds were used primarily to support capital spending and for other general corporate purposes, including the payment of natural gas purchases. Additionally, cash dividends increased due to an 8.7 percent increase in our dividend rate and an increase in shares outstanding.

The following table shows the number of shares issued for the fiscal years ended September 30, 2022, 2021 and 2020:

	For the Fiscal Year Ended September 30		
	2022	2021	2020
Shares issued:			
Direct Stock Purchase Plan	68,693	79,921	107,989
Retirement Savings Plan and Trust	72,339	84,265	78,941
1998 Long-Term Incentive Plan (LTIP)	427,929	242,216	254,706
Equity Issuance (1)	7,907,883	6,130,875	6,101,916
Total shares issued	8,476,844	6,537,277	6,543,552

(1) Share amounts do not include shares issued under forward sale agreements until the shares have been settled.

Credit Ratings

Our credit ratings directly affect our ability to obtain short-term and long-term financing, in addition to the cost of such financing. In determining our credit ratings, the rating agencies consider a number of quantitative factors, including but not limited to, debt to total capitalization, operating cash flow relative to outstanding debt, operating cash flow coverage of interest and operating cash flow less dividends to debt. In addition, the rating agencies consider qualitative factors such as consistency of our earnings over time, the risks associated with our business and the regulatory structures that govern our rates in the states where we operate.

Our debt is rated by two rating agencies: Standard & Poor's Corporation (S&P) and Moody's Investors Service (Moody's). As a result of the impacts of Winter Storm Uri, during the second quarter of fiscal 2021, S&P lowered our long-term and short-term credit ratings by one notch and placed our ratings under negative outlook. Additionally, Moody's placed our ratings under negative outlook. In February 2022, Moody's reaffirmed its long-term and short-term credit ratings and revised our outlook from negative to stable.

As of September 30, 2022, our outlook and current debt ratings, which are all considered investment grade are as follows:

	S&P	Moody's
Senior unsecured long-term debt	A-	A1
Short-term debt	A-2	P-1
Outlook	Negative	Stable

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of deteriorating global or national financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the two credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating is AAA for S&P and Aaa for Moody's. The lowest investment grade credit rating is BBB- for S&P and Baa3 for Moody's. Our credit ratings may be revised or withdrawn at any time by the rating agencies, and each rating should be evaluated independently of any other rating. There can be no assurance that a rating will remain in effect for any given period of time or that a rating will not be lowered, or withdrawn entirely, by a rating agency if, in its judgment, circumstances so warrant.

Debt Covenants

We were in compliance with all of our debt covenants as of September 30, 2022. Our debt covenants are described in Note 7 to the consolidated financial statements.

Contractual Obligations and Commercial Commitments

The following table provides information about contractual obligations and commercial commitments at September 30, 2022.

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(In thousands)				
Contractual Obligations					
Long-term debt (1)	$ 7,960,000	$ 2,200,000	$ —	$ 510,000	$ 5,250,000
Short-term debt (1)	184,967	184,967	—	—	—
Interest charges (2)	4,098,799	232,370	423,684	422,487	3,020,258
Finance leases (3)	73,193	3,313	6,813	7,070	55,997
Operating leases (4)	259,835	43,104	63,631	38,393	114,707
Financial instrument obligations (5)	4,129	3,000	1,129	—	—
Pension and postretirement benefit plan contributions (6)	359,479	35,636	91,664	63,831	168,348
Uncertain tax positions (7)	52,683	—	52,683	—	—
Total contractual obligations	$ 12,993,085	$ 2,702,390	$ 639,604	$ 1,041,781	$ 8,609,310

(1) Long-term and short-term debt excludes our finance lease obligations, which are separately reported within this table. See Note 7 to the consolidated financial statements for further details.
(2) Interest charges were calculated using the effective rate for each debt issuance through the contractual maturity date.
(3) Finance lease payments shown above include interest totaling $21.3 million. See Note 6 to the consolidated financial statements.
(4) Operating lease payments shown above include interest totaling $36.9 million. See Note 6 to the consolidated financial statements.
(5) Represents liabilities for natural gas commodity financial instruments that were valued as of September 30, 2022. The ultimate settlement amounts of these remaining liabilities are unknown because they are subject to continuing market risk until the financial instruments are settled.
(6) Represents expected contributions to our defined benefit and postretirement benefit plans, which are discussed in Note 10 to the consolidated financial statements.
(7) Represents liabilities associated with uncertain tax positions claimed or expected to be claimed on tax returns. The amount does not include interest and penalties that may be applied to these positions. See Note 14 to the consolidated financial statements for further details.

We maintain supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of individual contracts. Our Mid-Tex Division also maintains a limited number of long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market and fixed prices. At September 30, 2022, we were committed to purchase 55.6 Bcf within one year and 89.1 Bcf within two to three years under indexed contracts. At September 30, 2022, we were committed to purchase 13.2 Bcf within one year under fixed price contracts with a weighted average price of $5.39 per Mcf.

Risk Management Activities

In our distribution and pipeline and storage segments, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases. Additionally, we manage interest rate risk by entering into financial instruments to effectively fix the Treasury yield component of the interest cost associated with anticipated financings.

We record our financial instruments as a component of risk management assets and liabilities, which are classified as current or noncurrent based upon the anticipated settlement date of the underlying financial instrument. Substantially all of our financial instruments are valued using external market quotes and indices.

The following table shows the components of the change in fair value of our financial instruments for the fiscal year ended September 30, 2022 (in thousands):

Fair value of contracts at September 30, 2021	$ 225,417
Contracts realized/settled	(167,683)
Fair value of new contracts	2,998
Other changes in value	317,130
Fair value of contracts at September 30, 2022	377,862
Netting of cash collateral	—
Cash collateral and fair value of contracts at September 30, 2022	$ 377,862

The fair value of our financial instruments at September 30, 2022, is presented below by time period and fair value source:

	Fair Value of Contracts at September 30, 2022				
	Maturity in years				
Source of Fair Value	Less than 1	1-3	4-5	Greater than 5	Total Fair Value
			(In thousands)		
Prices actively quoted	$ 23,207	$ 290,267	$ 64,388	$ —	$ 377,862
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ 23,207	$ 290,267	$ 64,388	$ —	$ 377,862

RECENT ACCOUNTING DEVELOPMENTS

Recent accounting developments and their impact on our financial position, results of operations and cash flows are described in Note 2 to the consolidated financial statements.

ITEM 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

We are exposed to risks associated with commodity prices and interest rates. Commodity price risk is the potential loss that we may incur as a result of changes in the fair value of a particular instrument or commodity. Interest-rate risk is the potential increased cost we could incur when we issue debt instruments or to provide financing and liquidity for our business activities. Additionally, interest-rate risk could affect our ability to issue cost effective equity instruments.

We conduct risk management activities in our distribution and pipeline and storage segments. In our distribution segment, we use a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season. Our risk management activities and related accounting treatment are described in further detail in Note 15 to the consolidated financial statements. Additionally, our earnings are affected by changes in short-term interest rates as a result of our issuance of short-term commercial paper and our other short-term borrowings.

Commodity Price Risk

We purchase natural gas for our distribution operations. Substantially all of the costs of gas purchased for distribution operations are recovered from our customers through purchased gas cost adjustment mechanisms. Therefore, our distribution operations have limited commodity price risk exposure.

Interest Rate Risk

Our earnings are exposed to changes in short-term interest rates associated with our short-term commercial paper program and other short-term borrowings. We use a sensitivity analysis to estimate our short-term interest rate risk. For purposes of this analysis, we estimate our short-term interest rate risk as the difference between our actual interest expense for the period and estimated interest expense for the period assuming a hypothetical average one percent increase in the interest rates associated with our short-term borrowings. Had interest rates associated with our short-term borrowings increased by an average of one percent, our interest expense would not have materially increased during 2022.

ITEM 8. ***Financial Statements and Supplementary Data.***

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All financial statement schedules are omitted because the required information is not present, or not present in amounts sufficient to require submission of the schedule or because the information required is included in the financial statements and accompanying notes thereto.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Atmos Energy Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Atmos Energy Corporation (the Company) as of September 30, 2022 and 2021, the related consolidated statements of comprehensive income, shareholders' equity and cash flows for each of the three years in the period ended September 30, 2022, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at September 30, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2022, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of September 30, 2022, based on criteria established in Internal Control ─ Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated November 14, 2022 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of the critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

	Determination of Capital Costs
Description of the Matter	As more fully described in Note 2 to the financial statements, the Company capitalizes the direct and indirect costs of construction. Once a project is completed, it is placed into service and included in the Company's rate base. Costs of maintenance and repairs that are not included in the Company's rate base are charged to expense. For the year ended September 30, 2022, the Company capitalized approximately $2.4 billion of construction-related costs for regulated property, plant and equipment. Auditing management's identification of capital additions and maintenance and repairs expense involved significant effort and auditor judgment. These amounts have both a higher magnitude and a higher likelihood of potential misstatement. As a cost-based, rate-regulated entity, the rates charged to customers are designed to recover the entity's costs and provide a rate of return on rate base. Net property, plant and equipment is the most significant component of the Company's rate base. As a result, inappropriate capitalization of costs could affect the amount, timing and classification of revenues and expenses in the financial statements.

How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design and tested the operating effectiveness of the Company's controls over the initial determination and approval of expenditures for either capital additions or maintenance and repair. For example, we selected a sample of projects initiated during the year to evaluate the effectiveness of management's review controls to determine the proper categorization of project expenditures as either capitalizable costs or current-period expense. Our audit procedures included, among others, testing a sample of projects initiated during the year, including the evaluation of the nature of the project, with Company personnel outside of accounting and financial reporting. For example, we evaluated project setup through inspection of each project's description for compliance with the Company's capitalization policy as described in Note 2 and a series of inquiries of the project approver to understand how they assessed whether projects should be treated as capital or expense. Other audit procedures included evaluating whether the descriptions and amounts included on third-party invoices either support or contradict the project classification as capital, evaluating the appropriateness of individuals capitalizing direct labor charges to projects by assessing the relevance of their job function to the capital project, and recalculating other overhead costs capitalized to projects.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 1983.

Dallas, Texas
November 14, 2022

ATMOS ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	September 30	
	2022	2021
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$ 19,402,271	$ 17,258,547
Construction in progress	835,868	626,551
	20,238,139	17,885,098
Less accumulated depreciation and amortization	2,997,900	2,821,128
Net property, plant and equipment	17,240,239	15,063,970
Current assets		
Cash and cash equivalents	51,554	116,723
Accounts receivable, less allowance for uncollectible accounts of $49,993 in 2022 and $64,471 in 2021	363,708	342,967
Gas stored underground	357,941	178,116
Other current assets (See Note 9)	2,274,490	2,200,909
Total current assets	3,047,693	2,838,715
Goodwill	731,257	731,257
Deferred charges and other assets (See Note 9)	1,173,800	974,720
	$ 22,192,989	$ 19,608,662
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $0.005 per share); 200,000,000 shares authorized; issued and outstanding: 2022 — 140,896,598 shares; 2021 — 132,419,754 shares	$ 704	$ 662
Additional paid-in capital	5,838,118	5,023,751
Accumulated other comprehensive income	369,112	69,803
Retained earnings	3,211,157	2,812,673
Shareholders' equity	9,419,091	7,906,889
Long-term debt	5,760,647	4,930,205
Total capitalization	15,179,738	12,837,094
Commitments and contingencies (See Note 13)		
Current liabilities		
Accounts payable and accrued liabilities	496,019	423,222
Other current liabilities	720,157	686,681
Short-term debt	184,967	—
Current maturities of long-term debt	2,201,457	2,400,452
Total current liabilities	3,602,600	3,510,355
Deferred income taxes	1,999,505	1,705,809
Regulatory excess deferred taxes (See Note 14)	385,213	549,227
Regulatory cost of removal obligation	487,631	468,688
Deferred credits and other liabilities	538,302	537,489
	$ 22,192,989	$ 19,608,662

See accompanying notes to consolidated financial statements.

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended September 30		
	2022	2021	2020
	(In thousands, except per share data)		
Operating revenues			
Distribution segment	$ 4,035,194	$ 3,241,973	$ 2,626,993
Pipeline and storage segment	693,660	637,347	609,339
Intersegment eliminations	(527,192)	(471,830)	(415,195)
Total operating revenues	4,201,662	3,407,490	2,821,137
Purchased gas cost			
Distribution segment	2,210,302	1,501,695	1,071,227
Pipeline and storage segment	(1,583)	1,582	1,548
Intersegment eliminations	(526,063)	(470,560)	(413,921)
Total purchased gas cost	1,682,656	1,032,717	658,854
Operation and maintenance expense	710,161	679,019	629,601
Depreciation and amortization expense	535,655	477,977	429,828
Taxes, other than income	352,208	312,779	278,755
Operating income	920,982	904,998	824,099
Other non-operating income (expense)	33,737	(2,145)	7,171
Interest charges	102,811	83,554	84,474
Income before income taxes	851,908	819,299	746,796
Income tax expense	77,510	153,736	145,353
Net income	$ 774,398	$ 665,563	$ 601,443
Basic net income per share	$ 5.61	$ 5.12	$ 4.89
Diluted net income per share	$ 5.60	$ 5.12	$ 4.89
Weighted average shares outstanding:			
Basic	137,830	129,779	122,788
Diluted	138,096	129,834	122,872
Net income	$ 774,398	$ 665,563	$ 601,443
Other comprehensive income (loss), net of tax			
Net unrealized holding gains (losses) on available-for-sale securities, net of tax of $(157), $(55) and $32	(542)	(191)	106
Cash flow hedges:			
Amortization and unrealized gains on interest rate agreements, net of tax of $86,664, $36,875 and $17,198	299,851	127,583	56,888
Total other comprehensive income	299,309	127,392	56,994
Total comprehensive income	$ 1,073,707	$ 792,955	$ 658,437

See accompanying notes to consolidated financial statements.

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common stock					
	Number of Shares	Stated Value	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
	(In thousands, except share and per share data)					
Balance, September 30, 2019	119,338,925	$ 597	$ 3,712,194	$ (114,583)	$ 2,152,015	$ 5,750,223
Net income	—	—	—	—	601,443	601,443
Other comprehensive income	—	—	—	56,994	—	56,994
Cash dividends ($2.30 per share)	—	—	—	—	(282,444)	(282,444)
Common stock issued:						
Public offering	6,101,916	30	624,272	—	—	624,302
Direct stock purchase plan	107,989	1	11,325	—	—	11,326
Retirement savings plan	78,941	—	8,222	—	—	8,222
1998 Long-term incentive plan	254,706	1	2,748	—	—	2,749
Employee stock-based compensation	—	—	18,388	—	—	18,388
Balance, September 30, 2020	125,882,477	629	4,377,149	(57,589)	2,471,014	6,791,203
Net income	—	—	—	—	665,563	665,563
Other comprehensive income	—	—	—	127,392	—	127,392
Cash dividends ($2.50 per share)	—	—	—	—	(323,904)	(323,904)
Common stock issued:						
Public offering	6,130,875	31	606,636	—	—	606,667
Direct stock purchase plan	79,921	—	7,715	—	—	7,715
Retirement savings plan	84,265	1	8,125	—	—	8,126
1998 Long-term incentive plan	242,216	1	3,091	—	—	3,092
Employee stock-based compensation	—	—	21,035	—	—	21,035
Balance, September 30, 2021	132,419,754	662	5,023,751	69,803	2,812,673	7,906,889
Net income	—	—	—	—	774,398	774,398
Other comprehensive income	—	—	—	299,309	—	299,309
Cash dividends ($2.72 per share)	—	—	—	—	(375,914)	(375,914)
Common stock issued:						
Public offering	7,907,883	40	776,765	—	—	776,805
Direct stock purchase plan	68,693	—	7,495	—	—	7,495
Retirement savings plan	72,339	—	7,908	—	—	7,908
1998 Long-term incentive plan	427,929	2	2,396	—	—	2,398
Employee stock-based compensation	—	—	19,803	—	—	19,803
Balance, September 30, 2022	140,896,598	$ 704	$ 5,838,118	$ 369,112	$ 3,211,157	$ 9,419,091

See accompanying notes to consolidated financial statements.

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2022	2021	2020
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 774,398	$ 665,563	$ 601,443
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation and amortization	535,655	477,977	429,828
Deferred income taxes	53,651	155,355	155,322
One-time income tax benefit	—	—	(20,962)
Stock-based compensation	10,743	11,255	9,583
Amortization of debt issuance costs	9,141	14,030	11,543
Equity component of AFUDC	(45,505)	(32,749)	(23,493)
Other	3,265	3,731	8,411
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	(34,325)	(113,665)	7,167
(Increase) decrease in gas stored underground	(179,825)	(66,166)	18,188
Increase in Winter Storm Uri current regulatory asset (see Note 9)	—	(2,003,659)	—
Increase in other current assets	(65,979)	(84,705)	(35,878)
Increase in Winter Storm Uri long-term regulatory asset (see Note 9)	—	(76,652)	—
(Increase) decrease in deferred charges and other assets	13,287	136,809	(31,935)
Increase in accounts payable and accrued liabilities	40,394	104,242	7,359
Decrease in other current liabilities	(152,274)	(166,268)	(129,543)
Increase (decrease) in deferred credits and other liabilities	14,958	(109,349)	30,966
Net cash provided by (used in) operating activities	977,584	(1,084,251)	1,037,999
CASH FLOWS USED IN INVESTING ACTIVITIES			
Capital expenditures	(2,444,420)	(1,969,540)	(1,935,676)
Purchases of debt and equity securities	(28,285)	(49,879)	(50,517)
Proceeds from sale of debt and equity securities	4,872	14,957	32,339
Maturities of debt securities	27,586	28,850	18,669
Other, net	10,289	11,957	9,667
Net cash used in investing activities	(2,429,958)	(1,963,655)	(1,925,518)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net increase (decrease) in short-term debt	184,967	—	(464,915)
Proceeds from issuance of long-term debt, net of premium/discount	798,802	2,797,346	999,450
Net proceeds from equity offering	776,805	606,667	624,302
Issuance of common stock through stock purchase and employee retirement plans	15,403	15,841	19,548
Settlement of interest rate swaps	197,073	62,159	(4,426)
Repayment of long-term debt	(200,000)	—	—
Cash dividends paid	(375,914)	(323,904)	(282,444)
Debt issuance costs	(8,196)	(14,288)	(7,738)
Other	(1,735)	—	—
Net cash provided by financing activities	1,387,205	3,143,821	883,777
Net increase (decrease) in cash and cash equivalents	(65,169)	95,915	(3,742)
Cash and cash equivalents at beginning of year	116,723	20,808	24,550
Cash and cash equivalents at end of year	$ 51,554	$ 116,723	$ 20,808

See accompanying notes to consolidated financial statements.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Business

Atmos Energy Corporation (Atmos Energy or the "Company") and its subsidiaries are engaged in the regulated natural gas distribution and pipeline and storage businesses. Through our distribution business, we deliver natural gas through sales and transportation arrangements to approximately 3.3 million residential, commercial, public-authority and industrial customers through our six regulated distribution divisions in the service areas described below:

Division	Service Area
Atmos Energy Colorado-Kansas Division	Colorado, Kansas
Atmos Energy Kentucky/Mid-States Division	Kentucky, Tennessee, Virginia (1)
Atmos Energy Louisiana Division	Louisiana
Atmos Energy Mid-Tex Division	Texas, including the Dallas/Fort Worth metropolitan area
Atmos Energy Mississippi Division	Mississippi
Atmos Energy West Texas Division	West Texas

(1) Denotes location where we have more limited service areas.

In addition, we transport natural gas for others through our distribution system. Our distribution business is subject to federal and state regulation and/or regulation by local authorities in each of the states in which our distribution divisions operate. Our corporate headquarters and shared-services function are located in Dallas, Texas, and our customer support centers are located in Amarillo and Waco, Texas.

Our pipeline and storage business, which is also subject to federal and state regulation, consists of the pipeline and storage operations of our Atmos Pipeline–Texas (APT) Division and our natural gas transmission business in Louisiana. The APT division provides transportation and storage services to our Mid-Tex Division, other third-party local distribution companies, industrial and electric generation customers, as well as marketers and producers. As part of its pipeline operations, APT manages five underground storage facilities in Texas. We also provide ancillary services customary to the pipeline industry including parking arrangements, lending and sales of inventory on hand. Our natural gas transmission operations in Louisiana are comprised of a 21-mile pipeline located in the New Orleans, Louisiana area that is primarily used to aggregate gas supply for our distribution division in Louisiana under a long-term contract and on a more limited basis, to third parties.

2. Summary of Significant Accounting Policies

Principles of consolidation — The accompanying consolidated financial statements include the accounts of Atmos Energy Corporation and its wholly-owned subsidiaries. All material intercompany transactions have been eliminated; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates' rate regulation process.

Use of estimates — The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The most significant estimates include the allowance for doubtful accounts, unbilled revenues, contingency accruals, pension and postretirement obligations, deferred income taxes, impairment of long-lived assets, risk management and trading activities, fair value measurements and the valuation of goodwill and other long-lived assets. Actual results could differ from those estimates.

Regulation — Our distribution and pipeline and storage operations are subject to regulation with respect to rates, service, maintenance of accounting records and various other matters by the respective regulatory authorities in the states in which we operate. Our accounting policies recognize the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions. Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates. We record certain costs as regulatory assets when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. The amounts to be recovered or recognized are based upon historical experience and our understanding of the regulations. Further, regulation may impact the period in which revenues or expenses are recognized.

Substantially all of our regulatory assets are recorded as a component of other current assets and deferred charges and other assets and our regulatory liabilities are recorded as a component of other current liabilities and deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities and the long-term portion of regulatory excess deferred taxes and regulatory cost of removal obligation are reported separately. Significant regulatory assets and liabilities as of September 30, 2022 and 2021 included the following:

	September 30	
	2022	2021
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$ 31,122	$ 45,922
Infrastructure mechanisms [(1)]	235,972	222,795
Winter Storm Uri incremental costs [(2)]	2,109,454	2,100,728
Deferred gas costs	119,742	66,395
Regulatory excess deferred taxes [(3)]	47,311	45,370
Recoverable loss on reacquired debt	3,406	3,789
Deferred pipeline record collection costs	36,898	32,099
Other	21,467	4,343
	$ 2,605,372	$ 2,521,441
Regulatory liabilities:		
Regulatory excess deferred taxes [(3)]	$ 545,021	$ 705,084
Regulatory cost of removal obligation	568,307	541,511
Deferred gas costs	28,834	52,553
Asset retirement obligation	5,737	18,373
APT annual adjustment mechanism	31,138	31,110
Pension and postretirement benefit costs	156,857	56,201
Other	23,013	19,363
	$ 1,358,907	$ 1,424,195

(1) Infrastructure mechanisms in Texas, Louisiana and Tennessee allow for the deferral of all eligible expenses associated with capital expenditures incurred pursuant to these rules, including the recording of interest on the deferred expenses until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recovered through base rates.

(2) Includes extraordinary gas costs incurred during Winter Storm Uri and related carrying costs. See Note 9 to the consolidated financial statements for further information. This amount is recorded within other current assets and deferred charges and other assets on the consolidated balance sheet as of September 30, 2022 and 2021.

(3) Regulatory excess deferred taxes represent changes in our net deferred tax liability related to our cost of service ratemaking due to the enactment of the Tax Cuts and Jobs Act of 2017 (the "TCJA") and a Kansas legislative change enacted in fiscal 2020. See Notes 12 and 14 to the consolidated financial statements for further information.

Revenue recognition

Distribution Revenues

Distribution revenues represent the delivery of natural gas to residential, commercial, industrial and public authority customers at prices based on tariff rates established by regulatory authorities in the states in which we operate. Revenue is recognized and our performance obligation is satisfied over time when natural gas is delivered and simultaneously consumed by our customers. We have elected to use the invoice practical expedient and recognize revenue for volumes delivered that we have the right to invoice our customers. We bill our customers on a monthly cycle basis. Accordingly, we estimate volumes from the last meter read to the balance sheet date and accrue revenue for gas delivered but not yet billed.

In our Texas and Mississippi jurisdictions, we pay franchise fees and gross receipt taxes to operate in these service areas. These franchise fees and gross receipts taxes are required to be paid regardless of our ability to collect from our customers. Accordingly, we account for these amounts on a gross basis in revenue and we record the associated tax expense as a component of taxes, other than income.

Pipeline and Storage Revenues

Pipeline and storage revenues primarily represent the transportation and storage of natural gas on our APT system and the transmission of natural gas through our 21-mile pipeline in Louisiana. APT provides transportation and storage services to our

Mid-Tex Division, other third party local distribution companies and certain industrial customers under tariff rates approved by the RRC. APT also provides certain transportation and storage services to industrial and electric generation customers, as well as marketers and producers, under negotiated rates. Our pipeline in Louisiana is primarily used to aggregate gas supply for our Louisiana Division under a long-term contract and on a more limited basis to third parties. The demand fee charged to our Louisiana Division is subject to regulatory approval by the Louisiana Public Service Commission. We also manage two asset management plans with distribution affiliates of the Company at terms that have been approved by the applicable state regulatory commissions. The performance obligations for these transportation customers are satisfied by means of transporting customer-supplied gas to the designated location. Revenue is recognized and our performance obligation is satisfied over time when natural gas is delivered to the customer. Management determined that these arrangements qualify for the invoice practical expedient for recognizing revenue. For demand fee arrangements, revenue is recognized and our performance obligation is satisfied by standing ready to transport natural gas over the period of each individual month.

Alternative Revenue Program Revenues

In our distribution segment, we have weather-normalization adjustment mechanisms that serve to minimize the effects of weather on our residential and commercial revenues. Additionally, APT has a regulatory mechanism that requires that we share with its tariffed customers 75% of the difference between the total non-tariffed revenues earned during a test period and a revenue benchmark of $69.4 million that was established in its most recent rate case. Differences between actual revenues and revenues calculated under these mechanisms adjust the amount billed to customers. These mechanisms are considered to be alternative revenue programs under accounting standards generally accepted in the United States as they are deemed to be contracts between us and our regulator. Accordingly, revenue under these mechanisms are excluded from revenue from contracts with customers.

Purchased gas costs — Rates established by regulatory authorities are adjusted for increases and decreases in our purchased gas costs through purchased gas cost adjustment mechanisms. There is no margin generated through purchased gas cost adjustments, but they provide a dollar-for-dollar offset to increases or decreases in our distribution segment’s gas costs. The effects of these purchased gas cost adjustment mechanisms are recorded as deferred gas costs on our consolidated balance sheets.

Cash and cash equivalents — We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Accounts receivable and allowance for uncollectible accounts — Accounts receivable arise from natural gas sales to residential, commercial, industrial, public authority and other customers. Our accounts receivable balance includes unbilled amounts which represent a customer’s consumption of gas from the date of the last cycle billing through the last day of the month. The receivable balances are short term and generally do not extend beyond one month.

On October 1, 2020, we adopted new accounting guidance which requires credit losses on our accounts receivable to be measured using an expected credit loss model over the entire contractual term from the date of initial recognition. To minimize credit risk, we assess the credit worthiness of new customers, require deposits where necessary, assess late fees, pursue collection activities and disconnect service for nonpayment. After disconnection, accounts are written off when deemed uncollectible. At each reporting period, we assess the allowance for uncollectible accounts based on historical experience, current conditions and consideration of expected future conditions. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions.

Gas stored underground — Our gas stored underground is comprised of natural gas injected into storage to support the winter season withdrawals for our distribution operations. The average cost method is used for all of our distribution operations. Gas in storage that is retained as cushion gas to maintain reservoir pressure is classified as property, plant and equipment and is valued at cost.

Property, plant and equipment — Regulated property, plant and equipment is stated at original cost, net of contributions in aid of construction. The cost of additions includes direct construction costs, payroll related costs (taxes, the service cost portion of pension expense and other benefits), administrative and general costs and an allowance for funds used during construction (AFUDC). AFUDC represents the capitalizable total cost of funds used to finance the construction of major projects.

The following table details amounts capitalized for the fiscal year ended September 30.

Component of AFUDC	Statement of Comprehensive Income Location	2022	2021	2020
			(In thousands)	
Debt	Interest charges	$ 12,153	$ 11,414	$ 8,436
Equity	Other non-operating income (expense)	45,505	32,749	23,493
		$ 57,658	$ 44,163	$ 31,929

Major renewals, including replacement pipe, and betterments that are recoverable through our regulatory rate base are capitalized while the costs of maintenance and repairs that are not capitalizable are charged to expense as incurred. The costs of large projects are accumulated in construction in progress until the project is completed. When the project is completed, tested and placed in service, the balance is transferred to the regulated plant in service account included in the rate base and depreciation begins.

Regulated property, plant and equipment is depreciated at various rates on a straight-line basis. These rates are approved by our regulatory commissions and are comprised of two components: one based on average service life and one based on cost of removal. Accordingly, we recognize our cost of removal expense as a component of depreciation expense. The related cost of removal accrual is reflected as a regulatory liability on the consolidated balance sheet. At the time property, plant and equipment is retired, removal expenses less salvage, are charged to the regulatory cost of removal accrual. The composite depreciation rate was 3.0 percent for the fiscal years ended September 30, 2022, 2021 and 2020.

Other property, plant and equipment is stated at cost. Depreciation is generally computed on the straight-line method for financial reporting purposes based upon estimated useful lives.

Asset retirement obligations — We record a liability at fair value for an asset retirement obligation when the legal obligation to retire the asset has been incurred with an offsetting increase to the carrying value of the related asset.

We believe we have a legal obligation to retire our natural gas storage facilities. However, we have not recognized an asset retirement obligation associated with our storage facilities because we are not able to determine the settlement date of this obligation as we do not anticipate taking our storage facilities out of service permanently. Therefore, we cannot reasonably estimate the fair value of this obligation.

Impairment of long-lived assets — We evaluate whether events or circumstances have occurred that indicate that other long-lived assets may not be recoverable or that the remaining useful life may warrant revision. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying value of the asset, an impairment loss equal to the excess of the asset's carrying value over its fair value is recorded.

Goodwill — We annually evaluate our goodwill balances for impairment during our second fiscal quarter or more frequently as impairment indicators arise. During the second quarter of fiscal 2022, we completed our annual goodwill impairment assessment. We test goodwill for impairment at the reporting unit level on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of the reporting unit. Based on the assessment performed, we determined that our goodwill was not impaired. Although not applicable for the fiscal 2022 analysis, if a qualitative goodwill assessment resulted in impairment indicators, we would then use a present value technique based on discounted cash flows to estimate the fair value of our reporting units. These calculations are dependent on several subjective factors including the timing of future cash flows, future growth rates and the discount rate. An impairment charge is recognized if the carrying value of a reporting unit's goodwill exceeds its fair value.

Lease accounting — We adopted the provisions of the new lease accounting standard beginning on October 1, 2019. Results for reporting periods beginning on October 1, 2019 are presented under the new lease accounting standard and prior periods are presented under the former lease accounting standard. Upon adoption, we recorded right of use (ROU) assets and lease liabilities within the consolidated balance sheet.

We determine if an arrangement is a lease at the inception of the agreement based on the terms and conditions in the contract. A contract contains a lease if there is an identified asset and we have the right to control the asset. We are the lessee for substantially all of our leasing activities, which primarily includes operating leases for office and warehouse space, tower space, vehicles and heavy equipment used in our operations. We are also a lessee in finance leases for certain service centers.

We record a lease liability and a corresponding ROU asset for all of our leases with a term greater than 12 months. For lease contracts containing renewal and termination options, we include the option period in the lease term when it is reasonably certain the option will be exercised. We most frequently assume renewal options at the inception of the arrangement for our tower and fleet leases, based on our anticipated use of the assets. Real estate leases that contain a renewal option are evaluated on a lease-by-lease basis to determine if the option period should be included in the lease term. Currently, we have not included material renewal options for real estate leases in our ROU asset or lease liability.

The lease liability represents the present value of all lease payments over the lease term. We do not include short-term leases in the calculation of our lease liabilities. The discount rate used to determine the present value of the lease liability is the rate implicit in the lease unless that rate cannot be readily determined. We use the implicit rate stated in the agreement to determine the lease liability for our fleet leases. We use our corporate collateralized incremental borrowing rate as the discount rate for all other lease agreements. This rate is appropriate because we believe it represents the rate we would have incurred to borrow funds to acquire the leased asset over a similar term. We calculated this rate using a combination of inputs, including our current credit rating, quoted market prices of interest rates for our publicly traded unsecured debt, observable market yield curve data for peer companies with a credit rating one notch higher than our current credit rating and the lease term.

The ROU asset represents the right to use the underlying asset for the lease term, and is equal to the lease liability, adjusted for prepaid or accrued lease payments and any lease incentives that have been paid to us or when we are reasonably certain to incur costs equal to or greater than the allowance defined in the contract. We bundle our lease and non-lease components as a single component for all asset classes.

Variable payments included in our leasing arrangements are expensed in the period in which the obligation for these payments is incurred. Variable payments are dependent on usage, output or may vary for other reasons. Most of our variable lease expense is related to tower leases that have escalating payments based on changes to a stated CPI index, and usage of certain office equipment.

We have not provided material residual value guarantees for our leases, nor do our leases contain material restrictions or covenants.

Marketable securities — As of September 30, 2022, we hold marketable securities classified as either equity or debt securities. Changes in fair value of our equity securities are recorded in net income, while debt securities, which are considered available-for-sale securities, are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss).

On October 1, 2020, we adopted new accounting guidance that introduced an impairment recognition model for available-for-sale debt securities that requires credit losses to be recorded through an allowance account. We regularly evaluate the performance of our available-for-sale debt securities on an investment by investment basis for impairment, taking into consideration the securities' purpose, volatility and current returns. If a determination is made that a security will likely be sold before the recovery of its cost, the related investment is written down to its estimated fair value.

Financial instruments and hedging activities — We use financial instruments to mitigate commodity price risk in our distribution and pipeline and storage segments and to mitigate interest rate risk. The objectives and strategies for using financial instruments have been tailored to our business and are discussed in Note 15 to the consolidated financial statements.

We record all of our financial instruments on the balance sheet at fair value, with the exception of normal purchases and normal sales that are expected to result in physical delivery, with changes in fair value ultimately recorded in the statement of comprehensive income. These financial instruments are reported as risk management assets and liabilities and are classified as current or noncurrent other assets or liabilities based upon the anticipated settlement date of the underlying financial instrument. We record the cash flow impact of our financial instruments in operating cash flows based upon their balance sheet classification.

The timing of when changes in fair value of our financial instruments are recorded in the statement of comprehensive income depends on whether the financial instrument has been designated and qualifies as a part of a hedging relationship or if regulatory rulings require a different accounting treatment. Changes in fair value for financial instruments that do not meet one of these criteria are recognized in the statement of comprehensive income as they occur.

Financial Instruments Associated with Commodity Price Risk

In our distribution segment, the costs associated with and the realized gains and losses arising from the use of financial instruments to mitigate commodity price risk are included in our purchased gas cost adjustment mechanisms in accordance with regulatory requirements. Therefore, changes in the fair value of these financial instruments are initially recorded as a component of deferred gas costs and recognized in the consolidated statements of comprehensive income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue in accordance with accounting principles generally accepted in the United States. Accordingly, there is no earnings impact on our distribution segment as a result of the use of these financial instruments.

Financial Instruments Associated with Interest Rate Risk

In connection with the planned issuance of long-term debt, we may use financial instruments to manage interest rate risk. We currently manage this risk through the use of forward starting interest rate swaps to fix the Treasury yield component of the interest cost associated with anticipated financings. We designate these financial instruments as cash flow hedges at the time the agreements are executed. Unrealized gains and losses associated with the instruments are recorded as a component of accumulated other comprehensive income (loss). When the instruments settle, the realized gain or loss is recorded as a component of accumulated other comprehensive income (loss) and recognized as a component of interest charges over the life of the related financing arrangement. As of September 30, 2022 and 2021, no cash was required to be held in margin accounts.

Fair Value Measurements — We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We primarily use quoted market prices and other observable market pricing information in valuing our financial assets and liabilities and minimize the use of unobservable pricing inputs in our measurements.

Fair-value estimates also consider our own creditworthiness and the creditworthiness of the counterparties involved. Our counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and the use of collateral requirements under certain circumstances.

Amounts reported at fair value are subject to potentially significant volatility based upon changes in market prices, including, but not limited to, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions and interest rates, each of which directly affect the estimated fair value of our financial instruments. We believe the market prices and models used to value these financial instruments represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then current market conditions.

Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1) and the lowest priority given to unobservable inputs (Level 3). The levels of the hierarchy are described below:

Level 1 — Represents unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is defined as a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Prices actively quoted on national exchanges are used to determine the fair value of most of our assets and liabilities recorded on our balance sheet at fair value.

Our Level 1 measurements consist primarily of our debt and equity securities. The Level 1 measurements for investments in the Atmos Energy Corporation Master Retirement Trust (the Master Trust), Supplemental Executive Benefit Plan and postretirement benefit plan consist primarily of exchange-traded financial instruments.

Level 2 — Represents pricing inputs other than quoted prices included in Level 1 that are either directly or indirectly observable for the asset or liability as of the reporting date. These inputs are derived principally from, or corroborated by, observable market data. Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps and municipal and corporate bonds where market data for pricing is observable. The Level 2 measurements for investments in our Master Trust, Supplemental Executive Benefit Plan and postretirement benefit plan consist primarily of non-exchange traded financial instruments such as corporate bonds and government securities.

Level 3 — Represents generally unobservable pricing inputs which are developed based on the best information available, including our own internal data, in situations where there is little if any market activity for the asset or liability at the measurement date. The pricing inputs utilized reflect what a market participant would use to determine fair value. We currently do not have any Level 3 investments.

Pension and other postretirement plans — Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. Our measurement date is September 30. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligation and net pension and postretirement cost. When establishing our discount rate, we consider high quality corporate bond rates based on bonds available in the marketplace that are suitable for settling the obligations, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with currently available high quality corporate bonds.

The expected long-term rate of return on assets is utilized in calculating the expected return on plan assets component of the annual pension and postretirement plan cost. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors when making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater than or less than the assumed rate, that year's annual pension or postretirement plan cost is not affected. Rather, this gain or loss is amortized over the expected future working lifetime of the plan participants.

The expected return on plan assets is then calculated by applying the expected long-term rate of return on plan assets to the market-related value of the plan assets. The market-related value of our plan assets represents the fair market value of the plan assets, adjusted to smooth out short-term market fluctuations over a five-year period. The use of this calculation will delay the impact of current market fluctuations on the pension expense for the period.

We use a corridor approach to amortize actuarial gains and losses. Under this approach, net gains or losses in excess of ten percent of the larger of the pension benefit obligation or the market-related value of the assets are amortized on a straight-line basis. The period of amortization is the average remaining service of active participants who are expected to receive benefits under the plan.

We estimate the assumed health care cost trend rate used in determining our annual postretirement net cost based upon our actual health care cost experience, the effects of recently enacted legislation and general economic conditions. Our assumed rate of retirement is estimated based upon the annual review of our participant census information as of the measurement date.

We present only the current service cost component of the net benefit cost within operations and maintenance expense in the consolidated statements of comprehensive income. The remaining components of net benefit cost are recorded in other non-operating income (expense) in our consolidated statements of comprehensive income. Only the service cost component of net benefit cost is eligible for capitalization and we continue to capitalize these costs into property, plant and equipment. Additionally, we defer into a regulatory asset the portion of non-service components of net periodic benefit cost that are capitalizable for regulatory purposes.

Income taxes — Income taxes are determined based on the liability method, which results in income tax assets and liabilities arising from temporary differences. Temporary differences are differences between the tax bases of assets and liabilities and their reported amounts in the financial statements that will result in taxable or deductible amounts in future years. The liability method requires the effect of tax rate changes on accumulated deferred income taxes to be reflected in the period in which the rate change was enacted. The liability method also requires that deferred tax assets be reduced by a valuation allowance unless it is more likely than not that the assets will be realized.

The Company may recognize the tax benefit from uncertain tax positions only if it is at least more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon settlement with the taxing authorities. We recognize accrued interest related to unrecognized tax benefits as a component of interest charges. We recognize penalties related to unrecognized tax benefits as a component of miscellaneous income (expense) in accordance with regulatory requirements.

Tax collections — We are allowed to recover from customers revenue-related taxes that are imposed upon us. We record such taxes as operating expenses and record the corresponding customer charges as operating revenues. However, we do collect and remit various other taxes on behalf of various governmental authorities, and we record these amounts in our consolidated balance sheets on a net basis. We do not collect income taxes from our customers on behalf of governmental authorities.

Contingencies — In the normal course of business, we are confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties or the action of various regulatory agencies. For such matters, we record liabilities when they are considered probable and estimable, based on currently available facts and our estimates of the ultimate outcome or resolution of the liability in the future. We maintain liability insurance for various risks associated with the operation of our natural gas pipelines and facilities, including for property damage and bodily injury. These liability insurance policies generally require us to be responsible for the first $1.0 million (self-insured retention) of each incident. To the extent a loss contingency exceeds the self-insurance retention, we record an insurance receivable when recovery is considered probable. Upon reaching a settlement, the loss contingency is deemed resolved and recorded in accounts payable and accrued liabilities until paid. Loss contingencies and any related insurance recovery receivables reflect our best estimate of these amounts as of the date of this report. Actual results may differ from estimates, depending on actual outcomes or changes in the facts or expectations surrounding each potential exposure.

Subsequent events — Except as noted in Note 7 to the consolidated financial statements regarding the public offering of senior notes and Note 9 to the consolidated financial statements regarding the most recent update to our securitization filing in the State of Kansas, no events occurred subsequent to the balance sheet date that would require recognition or disclosure in the consolidated financial statements.

Recent accounting pronouncements

Accounting pronouncements adopted in fiscal 2022

In November 2021, the Financial Accounting Standards Board (FASB) issued guidance which will require disclosure about government assistance in the notes to the financial statements. The amendment requires annual disclosures about transactions with a government that are accounted for by applying a grant or contribution accounting model by analogy, including information about the nature of the transactions and the related accounting policy used to account for the transactions, the line items on the balance sheet and income statement that are affected by the transactions and the significant terms and conditions of the transactions, including commitments and contingencies. The amendment was effective for us beginning October 1, 2022; however, we elected to adopt this amendment during the first quarter of fiscal 2022 as permitted by the guidance. As the guidance is related only to disclosures in the notes to the financial statements, there was no impact on our financial position, results of operations or cash flows.

In March 2020, the FASB issued optional guidance which will ease the potential burden in accounting for recognizing the effects of reference rate reform on financial reporting. The amendments provide optional expedients and exceptions for applying U.S. GAAP to contracts, hedging relationships and other transactions affected by the cessation of the London Interbank Offered Rate (LIBOR). As discussed in Note 7, on March 31, 2022, we amended and restated our $1.5 billion credit facility and our $900 million unsecured revolving credit agreement which, among other things, included amending the interest rate provisions applicable to borrowings under this agreement to utilize the secured overnight financing rate as the reference rate, rather than LIBOR. In addition, we have evaluated the temporary expedients and options available under this guidance and identified the financial instruments to which the expedients could be applied, if deemed necessary. As of September 30, 2022, we have not applied any expedients or options available under these Accounting Standards Updates.

3. Segment Information

As of September 30, 2022, we manage and review our consolidated operations through the following two reportable segments:

- The *distribution segment* is primarily comprised of our regulated natural gas distribution and related sales operations in eight states.
- The *pipeline and storage segment* is comprised primarily of the pipeline and storage operations of our Atmos Pipeline-Texas division and our natural gas transmission operations in Louisiana.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers. Although our distribution segment operations are geographically dispersed, they are aggregated and reported as a single segment as each natural gas distribution division has similar economic characteristics. In addition, because the pipeline and storage operations of our Atmos Pipeline-Texas division and our natural gas transmission operations in Louisiana have similar economic characteristics, they have been aggregated and reported as a single segment.

The accounting policies of the segments are the same as those described in the summary of significant accounting policies. We evaluate performance based on net income or loss of the respective operating units. We allocate interest and pension expense to the pipeline and storage segment; however, there is no debt or pension liability recorded on the pipeline and storage segment balance sheet. All material intercompany transactions have been eliminated; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates' rate regulation process. Income taxes are allocated to each segment as if each segment's income taxes were calculated on a separate return basis.

Income statements and capital expenditures by segment are shown in the following tables.

	Year Ended September 30, 2022			
	Distribution	Pipeline and Storage	Eliminations	Consolidated
	(In thousands)			
Operating revenues from external parties	$ 4,031,936	$ 169,726	$ —	$ 4,201,662
Intersegment revenues	3,258	523,934	(527,192)	—
Total operating revenues	4,035,194	693,660	(527,192)	4,201,662
Purchased gas cost	2,210,302	(1,583)	(526,063)	1,682,656
Operation and maintenance expense	518,443	192,847	(1,129)	710,161
Depreciation and amortization expense	387,858	147,797	—	535,655
Taxes, other than income	314,046	38,162	—	352,208
Operating income	604,545	316,437	—	920,982
Other non-operating income	6,946	26,791	—	33,737
Interest charges	49,921	52,890	—	102,811
Income before income taxes	561,570	290,338	—	851,908
Income tax expense	39,593	37,917	—	77,510
Net income	$ 521,977	$ 252,421	$ —	$ 774,398
Capital expenditures	$ 1,675,798	$ 768,622	$ —	$ 2,444,420

	Year Ended September 30, 2021			
	Distribution	Pipeline and Storage	Eliminations	Consolidated
	(In thousands)			
Operating revenues from external parties	$ 3,238,753	$ 168,737	$ —	$ 3,407,490
Intersegment revenues	3,220	468,610	(471,830)	—
Total operating revenues	3,241,973	637,347	(471,830)	3,407,490
Purchased gas cost	1,501,695	1,582	(470,560)	1,032,717
Operation and maintenance expense	501,209	179,080	(1,270)	679,019
Depreciation and amortization expense	345,481	132,496	—	477,977
Taxes, other than income	275,074	37,705	—	312,779
Operating income	618,514	286,484	—	904,998
Other non-operating income (expense)	(20,694)	18,549	—	(2,145)
Interest charges	36,629	46,925	—	83,554
Income before income taxes	561,191	258,108	—	819,299
Income tax expense	115,329	38,407	—	153,736
Net income	$ 445,862	$ 219,701	$ —	$ 665,563
Capital expenditures	$ 1,454,195	$ 515,345	$ —	$ 1,969,540

	Year Ended September 30, 2020			
	Distribution	Pipeline and Storage	Eliminations	Consolidated
	(In thousands)			
Operating revenues from external parties	$ 2,624,251	$ 196,886	$ —	$ 2,821,137
Intersegment revenues	2,742	412,453	(415,195)	—
Total operating revenues	2,626,993	609,339	(415,195)	2,821,137
Purchased gas cost	1,071,227	1,548	(413,921)	658,854
Operation and maintenance expense	472,760	158,115	(1,274)	629,601
Depreciation and amortization expense	309,582	120,246	—	429,828
Taxes, other than income	245,181	33,574	—	278,755
Operating income	528,243	295,856	—	824,099
Other non-operating income (expense)	(1,265)	8,436	—	7,171
Interest charges	39,634	44,840	—	84,474
Income before income taxes	487,344	259,452	—	746,796
Income tax expense	91,680	53,673	—	145,353
Net income	$ 395,664	$ 205,779	$ —	$ 601,443
Capital expenditures	$ 1,466,631	$ 469,045	$ —	$ 1,935,676

The following table summarizes our revenues from external parties, excluding intersegment revenues, by products and services for the fiscal years ended September 30.

	2022	2021	2020
	(In thousands)		
Distribution revenues:			
Gas sales revenues:			
Residential	$ 2,492,116	$ 2,117,272	$ 1,717,070
Commercial	1,126,189	838,382	654,963
Industrial	224,632	113,171	89,641
Public authority and other	66,956	50,369	42,007
Total gas sales revenues	3,909,893	3,119,194	2,503,681
Transportation revenues	110,905	105,554	97,441
Other gas revenues	11,138	14,005	23,129
Total distribution revenues	4,031,936	3,238,753	2,624,251
Pipeline and storage revenues	169,726	168,737	196,886
Total operating revenues	$ 4,201,662	$ 3,407,490	$ 2,821,137

Balance sheet information at September 30, 2022 and 2021 by segment is presented in the following tables.

	September 30, 2022			
	Distribution	Pipeline and Storage	Eliminations	Consolidated
	(In thousands)			
Property, plant and equipment, net	$ 12,723,532	$ 4,516,707	$ —	$ 17,240,239
Total assets	$ 21,424,586	$ 4,797,206	$ (4,028,803)	$ 22,192,989

	September 30, 2021			
	Distribution	Pipeline and Storage	Eliminations	Consolidated
	(In thousands)			
Property, plant and equipment, net	$ 11,232,649	$ 3,831,321	$ —	$ 15,063,970
Total assets	$ 18,847,266	$ 4,076,844	$ (3,315,448)	$ 19,608,662

4. Earnings Per Share

We use the two-class method of computing earnings per share because we have participating securities in the form of non-vested restricted stock units with a nonforfeitable right to dividend equivalents, for which vesting is predicated solely on the passage of time. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. Basic weighted average shares outstanding is calculated based upon the weighted average number of common shares outstanding during the periods presented. Also, this calculation includes fully vested stock awards that have not yet been issued as common stock. Additionally, the weighted average shares outstanding for diluted EPS includes the incremental effects of the forward sale agreements, discussed in Note 8 to the consolidated financial statements, when the impact is dilutive.

Basic and diluted earnings per share for the fiscal years ended September 30 are calculated as follows:

	2022	2021	2020
	(In thousands, except per share data)		
Basic Earnings Per Share			
Net income	$ 774,398	$ 665,563	$ 601,443
Less: Income allocated to participating securities	508	465	444
Net income available to common shareholders	$ 773,890	$ 665,098	$ 600,999
Basic weighted average shares outstanding	137,830	129,779	122,788
Net income per share — Basic	$ 5.61	$ 5.12	$ 4.89
Diluted Earnings Per Share			
Net income available to common shareholders	$ 773,890	$ 665,098	$ 600,999
Effect of dilutive shares	—	—	—
Net income available to common shareholders	$ 773,890	$ 665,098	$ 600,999
Basic weighted average shares outstanding	137,830	129,779	122,788
Dilutive shares	266	55	84
Diluted weighted average shares outstanding	138,096	129,834	122,872
Net income per share — Diluted	$ 5.60	$ 5.12	$ 4.89

5. Revenue and Accounts Receivable

The following tables disaggregates our revenue from contracts with customers by customer type and segment and provides a reconciliation to total operating revenues, including intersegment revenues, for the periods presented.

	Year Ended September 30, 2022	
	Distribution	Pipeline and Storage
	(In thousands)	
Gas sales revenues:		
Residential	$ 2,472,461	$ —
Commercial	1,120,322	—
Industrial	224,427	—
Public authority and other	66,691	—
Total gas sales revenues	3,883,901	—
Transportation revenues	113,043	707,205
Miscellaneous revenues	10,282	13,679
Revenues from contracts with customers	4,007,226	720,884
Alternative revenue program revenues (1)	26,041	(27,224)
Other revenues	1,927	—
Total operating revenues	$ 4,035,194	$ 693,660

	Year Ended September 30, 2021	
	Distribution	Pipeline and Storage
Gas sales revenues:		
Residential	$ 2,129,704	$ —
Commercial	841,145	—
Industrial	113,091	—
Public authority and other	50,565	—
Total gas sales revenues	3,134,505	—
Transportation revenues	107,822	646,416
Miscellaneous revenues	10,971	14,141
Revenues from contracts with customers	3,253,298	660,557
Alternative revenue program revenues (1)	(13,303)	(23,210)
Other revenues	1,978	—
Total operating revenues	$ 3,241,973	$ 637,347

	Year Ended September 30, 2020	
	Distribution	Pipeline and Storage
Gas sales revenues:		
Residential	$ 1,704,444	$ —
Commercial	650,396	—
Industrial	89,467	—
Public authority and other	41,339	—
Total gas sales revenues	2,485,646	—
Transportation revenues	99,435	636,819
Miscellaneous revenues	19,085	9,754
Revenues from contracts with customers	2,604,166	646,573
Alternative revenue program revenues (1)	20,856	(37,234)
Other revenues	1,971	—
Total operating revenues	$ 2,626,993	$ 609,339

(1) In our distribution segment, we have weather-normalization adjustment mechanisms that serve to mitigate the effects of weather on our revenue. Additionally, APT has a regulatory mechanism that requires that we share with its tariffed customers 75% of the difference between the total non-tariffed revenues earned during a test period and a revenue benchmark.

Accounts receivable and allowance for uncollectible accounts

Rollforwards of our allowance for uncollectible accounts for the years ended September 30, 2022, 2021 and 2020 are presented in the table below.

In response to the COVID-19 pandemic, beginning in March 2020, regulators issued collection moratoriums, which required us to temporarily suspend our customer collection activities and charging late fees. After regulators lifted these moratoriums, we resumed customer collection activities during the third quarter of fiscal 2021. These regulatory orders influenced our bad debt expense and writeoffs from fiscal 2020 through 2022.

We actively work with our customers experiencing financial hardship to offer flexible payment options and to direct them to aid agencies for financial assistance. Our allowance for uncollectible accounts reflects the expected impact on our customers' ability to pay. Our allowance for uncollectible accounts also reflects the fact that we have the ability to recovery the gas cost portion of uncollectible accounts through our gas cost recovery mechanisms in five states, which covers approximately 81 percent of our residential and commercial customers.

	Allowance for uncollectible accounts
	(In thousands)
Balance, September 30, 2019	$ 15,899
Current period provisions	24,796
Write-offs charged against allowance	(12,698)
Recoveries of amounts previously written off	1,952
Balance, September 30, 2020	29,949
Current period provisions	43,807
Write-offs charged against allowance	(11,019)
Recoveries of amounts previously written off	1,734
Balance, September 30, 2021	64,471
Current period provisions	16,576
Write-offs charged against allowance	(32,885)
Recoveries of amounts previously written off	1,831
Balance, September 30, 2022	$ 49,993

6. Leases

We are the lessee for substantially all of our leasing activity, which primarily includes operating leases for office and warehouse space, tower space, vehicles and heavy equipment used in our operations. We are also a lessee in finance leases for service centers.

The following table presents our weighted average remaining lease term for our leases.

	September 30, 2022	September 30, 2021
Weighted average remaining lease term (years)		
Finance leases	18.7	19.0
Operating leases	9.7	10.2

The following table represents our weighted average discount rate:

	September 30, 2022	September 30, 2021
Weighted average discount rate		
Finance leases	4.0 %	5.7 %
Operating leases	2.9 %	2.8 %

Lease costs for the years ended September 30, 2022, 2021 and 2020 are presented in the table below. These costs include both amounts recognized in expense and amounts capitalized. For the years ended September 30, 2022, 2021 and 2020 we did not have material short-term lease costs or variable lease costs.

	Year Ended September 30		
	2022	2021	2020
	(In thousands)		
Finance lease cost	$ 4,314	$ 1,334	$ 622
Operating lease cost	43,394	42,349	40,887
Total lease cost	$ 47,708	$ 43,683	$ 41,509

Our ROU assets and lease liabilities are presented as follows on the consolidated balance sheets:

	Balance Sheet Classification	September 30, 2022	September 30, 2021
		(In thousands)	
Assets			
Finance leases	Net Property, Plant and Equipment	$ 50,118	$ 18,252
Operating leases	Deferred charges and other assets	214,663	222,446
Total right-of-use assets		$ 264,781	$ 240,698
Liabilities			
Current			
Finance leases	Current maturities of long-term debt	$ 1,457	$ 452
Operating leases	Other current liabilities	38,644	37,688
Noncurrent			
Finance leases	Long-term debt	50,393	18,287
Operating leases	Deferred credits and other liabilities	184,301	194,745
Total lease liabilities		$ 274,795	$ 251,172

Two service center leases are expected to commence in the fourth quarter of fiscal 2023 that impact our future lease payments. The total future lease payments for these leases are $48.1 million.

Other pertinent information related to leases was as follows. During the years ended September 30, 2022, 2021 and 2020 amounts paid in cash for our finance leases were not material.

	Year Ended September 30		
	2022	2021	2020
		(In thousands)	
Cash paid amounts included in the measurement of lease liabilities			
Operating cash flows used for operating leases	$ 45,080	$ 42,013	$ 37,758
Right-of-use assets obtained in exchange for lease obligations			
Finance leases	$ 33,833	$ 10,333	$ 6,083
Operating leases	$ 28,310	$ 25,690	$ 34,169

Maturities of our lease liabilities as of September 30, 2022 were as follows by fiscal years:

	Total	Finance Leases	Operating Leases
		(In thousands)	
2023	$ 46,417	$ 3,313	$ 43,104
2024	39,832	3,375	36,457
2025	30,612	3,438	27,174
2026	24,141	3,502	20,639
2027	21,322	3,568	17,754
Thereafter	170,704	55,997	114,707
Total lease payments	333,028	73,193	259,835
Less: Imputed interest	58,233	21,343	36,890
Total	$ 274,795	$ 51,850	$ 222,945
Reported as of September 30, 2022			
Short-term lease liabilities	$ 40,101	$ 1,457	$ 38,644
Long-term lease liabilities	234,694	50,393	184,301
Total lease liabilities	$ 274,795	$ 51,850	$ 222,945

7. Debt

Long-term debt

Long-term debt at September 30, 2022 and 2021 consisted of the following:

	2022	2021
	(In thousands)	
Unsecured 0.625% Senior Notes, due March 2023	$ 1,100,000	$ 1,100,000
Unsecured 3.00% Senior Notes, due June 2027	500,000	500,000
Unsecured 2.625% Senior Notes, due September 2029	500,000	300,000
Unsecured 1.50% Senior Notes, due January 2031	600,000	600,000
Unsecured 5.95% Senior Notes, due October 2034	200,000	200,000
Unsecured 5.50% Senior Notes, due June 2041	400,000	400,000
Unsecured 4.15% Senior Notes, due January 2043	500,000	500,000
Unsecured 4.125% Senior Notes, due October 2044	750,000	750,000
Unsecured 4.30% Senior Notes, due October 2048	600,000	600,000
Unsecured 4.125% Senior Notes, due March 2049	450,000	450,000
Unsecured 3.375% Senior Notes, due September 2049	500,000	500,000
Unsecured 2.85% Senior Notes, due February 2052	600,000	—
Floating-rate term loan, due April 2022	—	200,000
Floating-rate Senior Notes, due March 2023	1,100,000	1,100,000
Medium term Series A notes, 1995-1, 6.67%, due December 2025	10,000	10,000
Unsecured 6.75% Debentures, due July 2028	150,000	150,000
Finance lease obligations (see Note 6)	51,850	18,739
Total long-term debt	8,011,850	7,378,739
Less:		
Net original issue discount on unsecured senior notes and debentures	3,704	2,811
Debt issuance cost	46,042	45,271
Current maturities	2,201,457	2,400,452
	$ 5,760,647	$ 4,930,205

Maturities of long-term debt, excluding our finance lease obligations, at September 30, 2022 were as follows by fiscal years (in thousands):

2023	$ 2,200,000
2024	—
2025	—
2026	10,000
2027	500,000
Thereafter	5,250,000
	$ 7,960,000

On October 3, 2022, we completed a public offering of $500 million of 5.750% senior notes due fiscal 2053, with an effective interest rate of 4.504%, after giving effect to the estimated offering costs and settlement of our interest rate swaps, and $300 million of 5.450% senior notes due fiscal 2033, with an effective interest rate of 5.570%, after giving effect to the estimated offering costs. The net proceeds from the offering, after the underwriting discount and estimated offering expenses, of $789.4 million were used for general corporate purposes. In September 2022, we settled the interest rate swaps associated with the $500 million offering and received $197.1 million.

On January 14, 2022, we completed a public offering of $200 million of 2.625% senior notes due fiscal 2029, with an effective interest rate of 2.54%, after giving effect to the offering costs. The net proceeds from the offering, after the underwriting discount and offering expenses, of $200.8 million were used to repay our $200 million floating-rate term loan on January 18, 2022.

On October 1, 2021, we completed a public offering of $600 million of 2.85% senior notes due fiscal 2052, with an effective interest rate of 2.58%, after giving effect to the offering costs and settlement of our interest rate swaps. The net proceeds from the offering, after the underwriting discount and offering expenses, of $589.8 million, will be used for general corporate purposes. In September 2021, we settled the interest rate swaps associated with this offering and received $62.2 million.

On March 9, 2021, we completed a public offering of $1.1 billion of 0.625% senior notes due fiscal 2023, with an effective interest rate of 0.834%, after giving effect to the offering costs, and $1.1 billion floating rate senior notes due fiscal 2023 that bear interest at a rate equal to the Three-Month LIBOR rate plus 0.38%. The net proceeds from the offering, after the underwriting discount and offering expenses, of $2.2 billion were used for the payment of unplanned natural gas costs incurred during Winter Storm Uri. The notes are subject to optional redemption at any time on or after September 9, 2021 at a price equal to 100% of the principal amount of the notes being redeemed, plus any accrued and unpaid interest thereon, if any, to, but excluding, the redemption date. As discussed in Note 9 to the consolidated financial statements, we intend to repay these notes in fiscal 2023 after the expected receipt of securitization funds.

On October 1, 2020, we completed a public offering of $600 million of 1.50% senior notes due 2031, with an effective interest rate of 1.71%, after giving effect to the offering costs and settlement of our interest rate swaps. The net proceeds from the offering, after the underwriting discount and offering expenses, of $592.3 million, were used for general corporate purposes, including the repayment of working capital borrowings pursuant to our commercial paper program and the related settlement of our interest rate swaps.

Short-term Debt

We utilize short-term debt to provide cost-effective, short-term financing until it can be replaced with a balance of long-term debt and equity financing that achieves the Company’s desired capital structure with an equity-to-total-capitalization ratio between 50% and 60%, inclusive of long-term and short-term debt. Our short-term borrowing requirements are driven primarily by construction work in progress and the seasonal nature of the natural gas business.

Our short-term borrowing requirements are satisfied through a combination of a $1.5 billion commercial paper program and four committed revolving credit facilities with third-party lenders that provide $2.5 billion of total working capital funding.

The primary source of our funding is our commercial paper program, which is supported by a five-year unsecured $1.5 billion credit facility. On March 31, 2022, we amended this agreement to (i) extend the maturity date from March 31, 2026 to March 31, 2027 and (ii) replace the London interbank offered rate (the LIBOR Rate) with the forward-looking term rate based on the secured overnight financing rate (the SOFR Rate) as the interest rate benchmark. The facility now bears interest at a base rate or at a SOFR-based rate for the applicable interest period, plus a margin ranging from zero percent to 0.25 percent for base rate advances or a margin ranging from 0.75 percent to 1.25 percent for SOFR-based advances, based on the Company’s credit ratings. Additionally, the facility contains a $250 million accordion feature, which provides the opportunity to increase the total committed loan to $1.75 billion. At September 30, 2022, there was $185.0 million outstanding under our commercial paper program with a weighted average interest rate of 3.06% and weighted average maturities of less than one month. At September 30, 2021, there were no amounts outstanding under our commercial paper program

We also have a $900 million three-year unsecured revolving credit facility which is used to provide additional working capital funding. On March 31, 2022, we amended this agreement to (i) extend the maturity date from March 31, 2024 to March 31, 2025 and (ii) replace the LIBOR Rate with the SOFR Rate as the interest benchmark. This facility now bears interest at a base rate or at a SOFR-based rate for the applicable interest period, plus a margin ranging from zero percent to 0.25 percent for base rate advances or a margin ranging from 0.75 percent to 1.25 percent for SOFR-based advances, based on the Company's credit ratings. Additionally, the facility contains a $100 million accordion feature, which provides the opportunity to increase the total committed loan to $1.0 billion. At September 30, 2022 and 2021, there were no borrowings outstanding under this facility.

Additionally, we have a $50 million 364-day unsecured facility, which was renewed April 1, 2022 and is used to provide working capital funding. There were no borrowings outstanding under this facility as of September 30, 2022 and 2021.

Finally, we have a $50 million 364-day unsecured revolving credit facility, which was renewed March 31, 2022 and is used to issue letters of credit and to provide working capital funding. At September 30, 2022, there were no borrowings outstanding under the new facility; however, outstanding letters of credit reduced the total amount available to us to $44.4 million.

Debt Covenants

The availability of funds under these credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total-debt-to-total-capitalization of no greater than 70 percent. At September 30, 2022, our total-debt-to-total-capitalization ratio, as defined, was 47 percent. In addition, both the interest margin and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

These credit facilities and our public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers. Additionally, our public debt indentures relating to our senior notes and debentures, as well as certain of our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity. We were in compliance with all of our debt covenants as of September 30, 2022. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

8. Shareholders' Equity

Shelf Registration, At-the-Market Equity Sales Program and Equity Issuances

On June 29, 2021, we filed a shelf registration statement with the Securities and Exchange Commission (SEC) that allows us to issue up to $5.0 billion in common stock and/or debt securities, which expires June 29, 2024. At September 30, 2022, approximately $2.2 billion of securities remained available for issuance under the shelf registration statement. Following the completion of the $800 million senior unsecured notes offering on October 3, 2022 (see Note 7 to the consolidated financial statements), approximately $1.4 billion of securities remained available for issuance under the shelf registration statement.

On March 23, 2022, we filed a prospectus supplement under the shelf registration statement relating to an at-the-market (ATM) equity sales program under which we may issue and sell shares of our common stock up to an aggregate offering price of $1.0 billion through June 29, 2024 (including shares of common stock that may be sold pursuant to forward sale agreements entered into concurrently with the ATM equity sales program). This ATM equity sales program replaced our previous ATM equity sales program, filed on June 29, 2021, which was exhausted during our second fiscal quarter.

During the year ended September 30, 2022, we executed forward sales under our ATM equity sales programs with various forward sellers who borrowed and sold 11,862,319 shares of our common stock at an aggregate price of $1.3 billion. During the year ended September 30, 2022, we also settled forward sale agreements with respect to 7,907,883 shares that had been borrowed and sold by various forward sellers under the ATM program for net proceeds of $776.8 million. As of September 30, 2022, $481.7 million of equity was available for issuance under our existing ATM program. Additionally, we had $776.6 million in available proceeds from outstanding forward sale agreements, as detailed below.

Maturity	Shares Available	Net Proceeds Available (In Thousands)	Forward Price
September 29, 2023	4,552,157	$ 492,015	$ 108.08
December 29, 2023	919,898	105,451	$ 114.63
March 28, 2024	1,554,105	179,177	$ 115.29
Total	7,026,160	$ 776,643	$ 110.54

Accumulated Other Comprehensive Income (Loss)

We record deferred gains (losses) in accumulated other comprehensive income (AOCI) related to available-for-sale debt securities and interest rate agreement cash flow hedges. Deferred gains (losses) for our available-for-sale debt securities are recognized in earnings upon settlement, while deferred gains (losses) related to our interest rate agreement cash flow hedges are recognized in earnings as a component of interest charges, as they are amortized. The following tables provide the components of our accumulated other comprehensive income (loss) balances, net of the related tax effects allocated to each component of other comprehensive income (loss).

	Available-for-Sale Securities	Interest Rate Agreement Cash Flow Hedges	Total
		(In thousands)	
September 30, 2021	$ 47	$ 69,756	$ 69,803
Other comprehensive income (loss) before reclassifications	(542)	296,875	296,333
Amounts reclassified from accumulated other comprehensive income	—	2,976	2,976
Net current-period other comprehensive income (loss)	(542)	299,851	299,309
September 30, 2022	$ (495)	$ 369,607	$ 369,112

	Available-for-Sale Securities	Interest Rate Agreement Cash Flow Hedges	Total
		(In thousands)	
September 30, 2020	$ 238	$ (57,827)	$ (57,589)
Other comprehensive income (loss) before reclassifications	(191)	123,017	122,826
Amounts reclassified from accumulated other comprehensive income	—	4,566	4,566
Net current-period other comprehensive income (loss)	(191)	127,583	127,392
September 30, 2021	$ 47	$ 69,756	$ 69,803

9. Winter Storm Uri

Overview

A historic winter storm impacted supply, market pricing and demand for natural gas in our service territories in mid-February 2021. During this time, the governors of Kansas and Texas each declared a state of emergency, and certain regulatory agencies issued emergency orders that impacted the utility and natural gas industries, including statewide utilities curtailment programs and orders encouraging or requiring jurisdictional natural gas utilities to work to ensure customers were provided with safe and reliable natural gas service.

Due to the historic nature of this winter storm, we experienced unforeseeable and unprecedented market pricing for gas costs, which resulted in aggregated natural gas purchases during the month of February of approximately $2.3 billion. These gas costs were paid by the end of March 2021.

Incremental Financing

As discussed in Note 7 to the consolidated financial statements, on March 9, 2021, we completed a public offering of $2.2 billion in debt securities and the net proceeds from the offering, after the underwriting discount and offering expenses, were used to substantially fund these purchased gas costs. As a result of this unplanned debt issuance, S&P lowered its long-term/short-term credit ratings from A/A-1 to A-/A-2 and placed our ratings under negative outlook. Moody's reaffirmed its long-term and short-term credit ratings and placed our ratings under negative outlook, which was upgraded to stable in February 2022. These credit rating adjustments and the issuance of unplanned debt did not impact our ability to satisfy our debt covenants.

Regulatory Asset Accounting

Our purchased gas costs are recoverable through purchased gas cost adjustment mechanisms in each state where we operate. Due to the unprecedented level of purchased gas costs incurred during Winter Storm Uri, the Kansas Corporation Commission (KCC) and the Railroad Commission of Texas (RRC) issued orders authorizing natural gas utilities to record a regulatory asset to account for the extraordinary costs associated with the winter storm. Pursuant to these orders, as of September 30, 2022, we have recorded a $2.1 billion regulatory asset for incremental costs, including carrying costs, incurred in Kansas ($88.5 million) and Texas ($2,021.0 million).

Securitization Proceedings

To minimize the impact on the customer bill by extending the recovery periods for these unprecedented purchased gas costs, the Kansas and Texas State Legislatures each approved securitization legislation during fiscal 2021. The following summarizes the status of the securitization of each state as of the date of this filing.

Kansas

The Kansas securitization legislation, which became effective April 9, 2021, permits a natural gas public utility, in its sole discretion, to apply to the KCC for a financing order for the recovery of qualified extraordinary costs through the issuance of bonds. On September 14, 2021, we filed with the KCC an application to securitize $94.1 million of extraordinary gas costs incurred during Winter Storm Uri, which included an estimate of penalties, carrying costs and administrative costs that we expect to incur in connection with the resolution of this filing. On March 24, 2022, the KCC issued an Order Approving Unanimous Settlement Agreement which stipulated that all of our gas and storage costs were prudently incurred.

The KCC issued a financing order on October 25, 2022, which authorizes us to securitize, through the issuance of bonds, $118.5 million, which includes the carrying costs and estimated interest related to the securitization over a time period not to exceed 12 years. We expect the issuance of bonds to take place in the second quarter of fiscal 2023. Because we intend to securitize these costs and recover over several years, we have recorded the regulatory asset for Kansas as a long-term asset in deferred charges and other assets as of September 30, 2022.

Texas

On June 16, 2021, House Bill 1520 became effective. House Bill 1520 authorizes the RRC to issue a statewide securitization financing order directing the Texas Public Finance authority to issue bonds (customer rate relief bonds) for gas utilities that choose to participate to recover extraordinary costs incurred to secure gas supply and to provide service during Winter Storm Uri, and to restore gas utility systems after that event, thereby providing rate relief to customers by extending the period during which these extraordinary costs would otherwise be recovered and supporting the financial strength and stability of gas utility companies.

The legislation required natural gas utilities seeking to participate in the securitization program to file an application with the RRC and submit extraordinary gas costs incurred during Winter Storm Uri for a prudency review by July 30, 2021. We filed our application with the RRC on July 30, 2021 to securitize $2.0 billion of extraordinary gas costs incurred during Winter Storm Uri.

On November 10, 2021, the RRC issued a Final Determination of the Regulatory Asset (the Final Determination). The Final Determination stipulates that all of our gas and storage costs were prudently incurred. Additionally, the Final Determination permits us to defer, through December 31, 2021 our actual carrying costs associated with the $2.2 billion of incremental financing issued in March 2021 and to recover approximately $0.6 million of our administrative costs.

On February 8, 2022, the RRC issued a financing order that authorizes the Texas Public Financing Authority to issue customer rate relief bonds to securitize the costs that were approved in the Final Determination over a period not to exceed 30 years. Upon receipt of the securitization funds we will repay the $2.2 billion in public notes issued to finance the incremental gas costs incurred during Winter Storm Uri.

10. Retirement and Postretirement Employee Benefit Plans

We have both funded and unfunded noncontributory defined benefit plans that together cover most of our employees. We also maintain a postretirement plan that provides health care benefits to retired employees. Finally, we sponsor a defined contribution plan that covers substantially all employees. These plans are discussed in further detail below.

As a rate regulated entity, most of our net periodic pension and other postretirement benefits costs are recoverable through our rates over a period of up to 15 years. A portion of these costs is capitalized into our rate base or deferred as a regulatory asset or liability. The remaining costs are recorded as a component of operation and maintenance expense or other non-operating expense. Additionally, the amounts that have not yet been recognized in net periodic pension cost that have been recorded as regulatory assets or liabilities are as follows:

	Employee Pension Plan	Supplemental Executive Retirement Plans	Postretirement Plan	Total
	(In thousands)			
September 30, 2022				
Unrecognized prior service credit	$ (121)	$ —	$ (51,079)	$ (51,200)
Unrecognized actuarial (gain) loss	(32,159)	14,029	(87,527)	(105,657)
	$ (32,280)	$ 14,029	$ (138,606)	$ (156,857)
September 30, 2021				
Unrecognized prior service credit	$ (353)	$ —	$ (64,313)	$ (64,666)
Unrecognized actuarial (gain) loss	(3,060)	39,666	(28,141)	8,465
	$ (3,413)	$ 39,666	$ (92,454)	$ (56,201)

Defined Benefit Plans

Employee Pension Plan

As of September 30, 2022, we maintained one cash balance defined benefit plan, the Atmos Energy Corporation Pension Account Plan (the Pension Plan). The Pension Plan was established effective January 1999 and covers most of the employees of Atmos Energy that were hired on or before September 30, 2010. Effective October 1, 2010, the Pension Plan was closed to new participants. The assets of the Pension Plan are held within the Atmos Energy Corporation Master Retirement Trust (the Master Trust).

Opening account balances were established for participants as of January 1999 equal to the present value of their respective accrued benefits under the pension plans which were previously in effect as of December 31, 1998. The Pension Plan credits an allocation to each participant's account at the end of each year according to a formula based on the participant's age, service and total pay (excluding incentive pay). In addition, at the end of each year, a participant's account is credited with interest on the employee's prior year account balance. Participants are fully vested in their account balances after three years of service and may choose to receive their account balances as a lump sum or an annuity.

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974 (ERISA), including the funding requirements under the Pension Protection Act of 2006 (PPA). However, additional voluntary contributions are made from time to time as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future.

During fiscal 2022 and 2021, we contributed $8.5 million and $10.0 million in cash to the Pension Plan to achieve a desired level of funding while maximizing the tax deductibility of this payment. Based upon market conditions at September 30, 2022, the current funded position of the Pension Plan and the funding requirements under the PPA, we do not anticipate a minimum required contribution for fiscal 2023. However, we may consider whether a voluntary contribution is prudent to maintain certain funding levels.

We make investment decisions and evaluate performance of the assets in the Master Trust on a medium-term horizon of at least three to five years. We also consider our current financial status when making recommendations and decisions regarding the Master Trust's assets. Finally, we strive to ensure the Master Trust's assets are appropriately invested to maintain an acceptable level of risk and meet the Master Trust's long-term asset investment policy adopted by the Board of Directors.

To achieve these objectives, we invest the Master Trust's assets in equity securities, fixed income securities, interests in commingled pension trust funds, other investment assets and cash and cash equivalents. Investments in equity securities are diversified among the market's various subsectors in an effort to diversify risk and maximize returns. Fixed income securities are invested in investment grade securities. Cash equivalents are invested in securities that either are short term (less than 180 days) or readily convertible to cash with modest risk.

The following table presents asset allocation information for the Master Trust as of September 30, 2022 and 2021.

Security Class	Targeted Allocation Range	Actual Allocation September 30 2022	Actual Allocation September 30 2021
Domestic equities	35%-55%	39.7%	44.5%
International equities	10%-20%	14.6%	16.9%
Fixed income	5%-30%	16.0%	16.0%
Company stock	0%-15%	15.3%	10.6%
Other assets	0%-20%	14.4%	12.0%

At September 30, 2022 and 2021, the Pension Plan held 716,700 shares of our common stock which represented 15.3 percent and 10.6 percent of total Pension Plan assets. These shares generated dividend income for the Pension Plan of approximately $1.9 million and $1.8 million during fiscal 2022 and 2021.

Our Pension Plan expenses and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets and assumed discount rates and demographic data. We review the estimates and assumptions underlying our Pension Plan annually based upon a September 30 measurement date. The development of our assumptions is fully described in our significant accounting policies in Note 2 to the consolidated financial statements. The actuarial assumptions used to determine the pension liability for the Pension Plan was determined as of September 30, 2022 and 2021 and the actuarial assumptions used to determine the net periodic pension cost for the Pension Plan was determined as of September 30, 2021, 2020 and 2019.

Additional assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2022	2021	2022	2021	2020
Discount rate	5.66 %	2.97 %	2.97 %	2.80 %	3.29 %
Rate of compensation increase	3.50 %	3.50 %	3.50 %	3.50 %	3.50 %
Expected return on plan assets	6.25 %	6.25 %	6.25 %	6.25 %	6.50 %
Interest crediting rate	4.69 %	4.69 %	4.69 %	4.69 %	4.69 %

The following table presents the Pension Plan's accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2022 and 2021:

	2022	2021
	(In thousands)	
Accumulated benefit obligation	$ 428,629	$ 558,639
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 596,029	$ 604,221
Service cost	16,165	17,369
Interest cost	17,606	16,883
Actuarial gain	(141,567)	(7,561)
Benefits paid	(38,706)	(34,883)
Benefit obligation at end of year	449,527	596,029
Change in plan assets:		
Fair value of plan assets at beginning of year	596,806	528,881
Actual return on plan assets	(87,575)	92,808
Employer contributions	8,500	10,000
Benefits paid	(38,706)	(34,883)
Fair value of plan assets at end of year	479,025	596,806
Reconciliation:		
Funded status	29,498	777
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Net amount recognized	$ 29,498	$ 777

Net periodic pension cost for the Pension Plan for fiscal 2022, 2021 and 2020 is presented in the following table.

	Fiscal Year Ended September 30		
	2022	2021	2020
		(In thousands)	
Components of net periodic pension cost:			
Service cost	$ 16,165	$ 17,369	$ 17,551
Interest cost [1]	17,606	16,883	19,028
Expected return on assets [1]	(29,531)	(27,913)	(28,316)
Amortization of prior service credit [1]	(231)	(231)	(231)
Recognized actuarial loss [1]	4,638	8,686	9,025
Net periodic pension cost	$ 8,647	$ 14,794	$ 17,057

(1) The components of net periodic cost other than the service cost component are included in the line item other non-operating income (expense) in the consolidated statements of comprehensive income or are capitalized on the consolidated balance sheets as a regulatory asset or liability, as described in Note 2 to the consolidated financial statements.

The following tables set forth by level, within the fair value hierarchy, the Pension Plan's assets at fair value as of September 30, 2022 and 2021. As required by authoritative accounting literature, assets are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement. The methods used to determine fair value for the assets held by the Pension Plan are fully described in Note 2 to the consolidated financial statements. Investments in our common/collective trusts and limited partnerships that are measured at net asset value per share equivalent are not classified in the fair value hierarchy. The net asset value amounts presented are intended to reconcile the fair value hierarchy to the total investments. In addition to the assets shown below, the Pension Plan had net accounts receivable of $2.4 million and $2.1 million at September 30, 2022 and 2021, which materially approximates fair value due to the short-term nature of these assets.

	Assets at Fair Value as of September 30, 2022			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Investments:				
Common stocks	$ 210,325	$ —	$ —	$ 210,325
Money market funds	—	14,490	—	14,490
Registered investment companies	53,401	—	—	53,401
Government securities:				
Mortgage-backed securities	—	14,175	—	14,175
U.S. treasuries	3,681	28	—	3,709
Corporate bonds	—	22,320	—	22,320
Total investments measured at fair value	$ 267,407	$ 51,013	$ —	318,420
Investments measured at net asset value:				
Common/collective trusts (1)				86,891
Limited partnerships (1)				71,331
Total investments				$ 476,642

	Assets at Fair Value as of September 30, 2021			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Investments:				
Common stocks	$ 239,166	$ —	$ —	$ 239,166
Money market funds	—	7,060	—	7,060
Registered investment companies	74,236	—	—	74,236
Government securities:				
Mortgage-backed securities	—	14,048	—	14,048
U.S. treasuries	7,483	34	—	7,517
Corporate bonds	—	30,834	—	30,834
Total investments measured at fair value	$ 320,885	$ 51,976	$ —	372,861
Investments measured at net asset value:				
Common/collective trusts (1)				121,570
Limited partnerships (1)				100,299
Total investments				$ 594,730

(1) The fair value of our common/collective trusts and limited partnerships are measured using the net asset value per share practical expedient. There are no redemption restrictions, redemption notice periods or unfunded commitments for these investments. The redemption frequency is daily.

Supplemental Executive Retirement Plans

We have three nonqualified supplemental plans (the Supplemental Plans) which provide additional pension, disability and death benefits to our officers and certain other employees of the Company.

The Supplemental Executive Benefits Plan (SEBP) covers our corporate officers and certain other employees of the Company who were employed on or before August 12, 1998. The SEBP is a defined benefit arrangement which provides a benefit equal to 75 percent of covered compensation under which benefits paid from the underlying qualified defined benefit plan are an offset to the benefits under the SEBP.

In August 1998, we adopted the Supplemental Executive Retirement Plan (SERP) (formerly known as the Performance-Based Supplemental Executive Benefits Plan), which covers all corporate officers selected to participate in the plan between August 12, 1998 and August 5, 2009. The SERP is a defined benefit arrangement which provides a benefit equal to 60 percent of covered compensation under which benefits paid from the underlying qualified defined benefit plan are an offset to the benefits under the SERP.

Effective August 5, 2009, we adopted a new defined benefit Supplemental Executive Retirement Plan (the 2009 SERP), for corporate officers or any other employees selected at the discretion of the Board. Under the 2009 SERP, a nominal account has been established for each participant, to which the Company contributes at the end of each calendar year an amount equal to ten percent (25 percent for members of the Management Committee appointed on or after January 1, 2016) of the total of each participant's base salary and cash incentive compensation earned during each prior calendar year, beginning December 31, 2009. The benefits vest after three years of service and attainment of age 55 and earn interest credits at the same annual rate as the Company's Pension Plan.

During fiscal 2021, we recognized a settlement charge of $9.2 million and paid a $25.7 million lump sum in relation to the retirements of certain executives.

We review the estimates and assumptions underlying our Supplemental Plans annually based upon a September 30 measurement date using the same techniques as our Pension Plan. The actuarial assumptions used to determine the pension liability for the Supplemental Plans were determined as of September 30, 2022 and 2021 and the actuarial assumptions used to determine the net periodic pension cost for the Supplemental Plans were determined as of September 30, 2021, 2020 and 2019. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2022	2021	2022	2021	2020
Discount rate [1]	5.71 %	2.57 %	2.57 %	2.90 %	3.19 %
Rate of compensation increase	3.50 %	3.50 %	3.50 %	3.50 %	3.50 %
Interest crediting rate	4.69 %	4.69 %	4.69 %	4.69 %	4.69 %

(1) Reflects a weighted average discount rate for pension cost for fiscal 2021 and 2020 due to the settlements during the year.

The following table presents the Supplemental Plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2022 and 2021:

	2022	2021
	(In thousands)	
Accumulated benefit obligation	$ 79,233	$ 100,981
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 104,301	$ 129,140
Service cost	1,129	1,067
Interest cost	2,647	3,180
Actuarial (gain) loss	(22,471)	1,332
Benefits paid	(4,831)	(4,720)
Settlements	—	(25,698)
Benefit obligation at end of year	80,775	104,301
Change in plan assets:		
Fair value of plan assets at beginning of year	—	—
Employer contribution	4,831	30,418
Benefits paid	(4,831)	(4,720)
Settlements	—	(25,698)
Fair value of plan assets at end of year	—	—
Reconciliation:		
Funded status	(80,775)	(104,301)
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Accrued pension cost	$ (80,775)	$ (104,301)

Assets for the Supplemental Plans are held in separate rabbi trusts. At September 30, 2022 and 2021, assets held in the rabbi trusts consisted of equity securities of $30.2 million and $38.1 million, which are included in our fair value disclosures in Note 16 to the consolidated financial statements.

Net periodic pension cost for the Supplemental Plans for fiscal 2022, 2021 and 2020 is presented in the following table.

	Fiscal Year Ended September 30		
	2022	2021	2020
		(In thousands)	
Components of net periodic pension cost:			
Service cost	$ 1,129	$ 1,067	$ 1,074
Interest cost (1)	2,647	3,180	4,188
Recognized actuarial loss (1)	3,166	3,560	3,945
Settlements (1)	—	9,151	9,180
Net periodic pension cost	$ 6,942	$ 16,958	$ 18,387

(1) The components of net periodic cost other than the service cost component are included in the line item other non-operating income (expense) in the consolidated statements of comprehensive income or are capitalized on the consolidated balance sheets as a regulatory asset or liability, as described in Note 2 to the consolidated financial statements.

Estimated Future Benefit Payments

The following benefit payments for our defined benefit plans, which reflect expected future service, as appropriate, are expected to be paid in the following fiscal years:

	Pension Plan	Supplemental Plans
	(In thousands)	
2023	$ 40,569	$ 9,995
2024	40,126	9,538
2025	40,396	30,135
2026	41,611	6,594
2027	41,358	3,946
2028-2032	198,156	27,420

Postretirement Benefits Plan

We sponsor the Retiree Medical Plan for Retirees and Disabled Employees of Atmos Energy Corporation (the Retiree Medical Plan). This plan provides medical and prescription drug protection to all qualified participants based on their date of retirement. The Retiree Medical Plan provides different levels of benefits depending on the level of coverage chosen by the participants and the terms of predecessor plans; however, we generally pay 80 percent of the projected net claims and administrative costs and participants pay the remaining 20 percent. Effective January 1, 2015, for employees who had not met the participation requirements by September 30, 2009, the contribution rates for the Company were limited to a three percent cost increase in claims and administrative costs each year, with the participant responsible for the additional costs. Effective January 1, 2022, the Retiree Medical Plan was amended to remove the three percent cost increase limitation and change the post-65 retiree coverage to Via Benefits with an Atmos Energy funded Health Reimbursement Account. Eligible post-65 retirees and post-65 spouses will be eligible to enroll in benefits provided by Via Benefits, including those that previously deferred or declined retiree coverage.

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of ERISA. However, additional voluntary contributions are made annually as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future. We expect to contribute between $15 million and $25 million to our Retiree Medical Plan during fiscal 2023.

We maintain a formal investment policy with respect to the assets in our Retiree Medical Plan to ensure the assets funding the Retiree Medical Plan are appropriately invested to maintain an acceptable level of risk. We also consider our current financial status when making recommendations and decisions regarding the Retiree Medical Plan.

We currently invest the assets funding our Retiree Medical Plan in diversified investment funds which consist of common stocks, preferred stocks and fixed income securities. The diversified investment funds may invest up to 75 percent of assets in common stocks and convertible securities. The following table presents asset allocation information for the Retiree Medical Plan assets as of September 30, 2022 and 2021.

	Actual Allocation September 30	
Security Class	2022	2021
Diversified investment funds	97.7%	97.9%
Cash and cash equivalents	2.3%	2.1%

We review the estimates and assumptions underlying our Retiree Medical Plan annually based upon a September 30 measurement date using the same techniques as our Pension Plan and Supplemental Plans. The actuarial assumptions used to determine the pension liability for our Retiree Medical Plan were determined as of September 30, 2022 and 2021 and the actuarial assumptions used to determine the net periodic pension cost for the Retiree Medical Plan were determined as of September 30, 2021, 2020 and 2019.

The assumptions are presented in the following table:

	Postretirement Liability		Postretirement Cost		
	2022	2021	2022	2021	2020
Discount rate	5.61 %	3.01 %	3.01 %	2.80 %	3.29 %
Expected return on plan assets	4.94 %	4.94 %	4.94 %	4.94 %	5.14 %
Initial trend rate	6.25 %	6.25 %	6.25 %	6.25 %	6.25 %
Ultimate trend rate	4.75 %	5.00 %	5.00 %	5.00 %	5.00 %
Ultimate trend reached in	2029	2027	2027	2026	2025

The following table presents the Retiree Medical Plan's benefit obligation and funded status as of September 30, 2022 and 2021:

	2022	2021
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 355,156	$ 370,678
Service cost	10,235	11,000
Interest cost	10,734	15,372
Plan participants' contributions	3,210	5,648
Actuarial (gain) loss	(112,748)	6,800
Benefits paid	(16,359)	(19,610)
Plan amendments	—	(34,732)
Benefit obligation at end of year	250,228	355,156
Change in plan assets:		
Fair value of plan assets at beginning of year	268,199	208,245
Actual return on plan assets	(40,113)	53,335
Employer contributions	14,749	20,581
Plan participants' contributions	3,210	5,648
Benefits paid	(16,359)	(19,610)
Fair value of plan assets at end of year	229,686	268,199
Reconciliation:		
Funded status	(20,542)	(86,957)
Unrecognized transition obligation	—	—
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Accrued postretirement cost	$ (20,542)	$ (86,957)

Net periodic postretirement cost for the Retiree Medical Plan for fiscal 2022, 2021 and 2020 is presented in the following table.

	Fiscal Year Ended September 30		
	2022	2021	2020
		(In thousands)	
Components of net periodic postretirement cost:			
Service cost	$ 10,235	$ 11,000	$ 13,466
Interest cost [(1)]	10,734	15,372	10,612
Expected return on assets [(1)]	(13,249)	(10,455)	(10,499)
Amortization of prior service (credit) cost [(1)]	(13,234)	30,533	173
Recognized actuarial (gain) loss [(1)]	—	1,172	(1,337)
Net periodic postretirement cost	$ (5,514)	$ 47,622	$ 12,415

(1) The components of net periodic cost other than the service cost component are included in the line item other non-operating income (expense) in the consolidated statements of comprehensive income or are capitalized on the consolidated balance sheets as a regulatory asset or liability, as described in Note 2 to the consolidated financial statements.

We are currently recovering other postretirement benefits costs through our regulated rates in substantially all of our service areas under accrual accounting as prescribed by accounting principles generally accepted in the United States. Other postretirement benefits costs have been specifically addressed in rate orders in each jurisdiction served by our Kentucky/Mid-States, West Texas, Mid-Tex and Mississippi Divisions as well as our Kansas jurisdiction and APT or have been included in a rate case and not disallowed. Management believes that this accounting method is appropriate and will continue to seek rate recovery of accrual-based expenses in its ratemaking jurisdictions that have not yet approved the recovery of these expenses.

The following tables set forth by level, within the fair value hierarchy, the Retiree Medical Plan's assets at fair value as of September 30, 2022 and 2021. The methods used to determine fair value for the assets held by the Retiree Medical Plan are fully described in Note 2 to the consolidated financial statements.

	Assets at Fair Value as of September 30, 2022			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Money market funds	$ —	$ 5,214	$ —	$ 5,214
Registered investment companies	224,472	—	—	224,472
Total investments measured at fair value	$ 224,472	$ 5,214	$ —	$ 229,686

	Assets at Fair Value as of September 30, 2021			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Money market funds	$ —	$ 5,527	$ —	$ 5,527
Registered investment companies	262,672	—	—	262,672
Total investments measured at fair value	$ 262,672	$ 5,527	$ —	$ 268,199

Estimated Future Benefit Payments

The following benefit payments paid by the Company, retirees and prescription drug subsidies for our Retiree Medical Plan, which reflect expected future service, as appropriate, are expected to be paid in the following fiscal years.

	Company Payments	Retiree Payments	Subsidy Payments	Total Postretirement Benefits
		(In thousands)		
2023	$ 17,141	$ 2,445	$ —	$ 19,586
2024	17,409	2,410	—	19,819
2025	17,582	2,314	—	19,896
2026	18,022	2,282	—	20,304
2027	18,269	2,193	—	20,462
2028-2032	94,528	9,638	—	104,166

Defined Contribution Plan

The Atmos Energy Corporation Retirement Savings Plan and Trust (the Retirement Savings Plan) covers substantially all employees and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Effective January 1, 2007, employees automatically become participants of the Retirement Savings Plan on the date of employment. Participants may elect a salary reduction up to a maximum of 65 percent of eligible compensation, as defined by the Retirement Savings Plan, not to exceed the maximum allowed by the Internal Revenue Service. New participants are automatically enrolled in the Retirement Savings Plan at a contribution rate of four percent of eligible compensation, from which they may opt out. We match 100 percent of a participant's contributions, limited to four percent of the participant's salary. Prior to January 1, 2021, participants were eligible to receive matching contributions after completing one year of service, in which they are immediately vested.

Effective January 1, 2021, participants are eligible to receive matching contributions immediately upon enrollment in the Retirement Savings Plan. This matching contribution vests after completing one year of service. Participants are also permitted to take out a loan against their accounts subject to certain restrictions. Employees hired on or after October 1, 2010 participate in the enhanced plan in which participants receive a fixed annual contribution of four percent of eligible earnings to their Retirement Savings Plan account. Participants will continue to be eligible for company matching contributions of up to four percent of their eligible earnings and will be fully vested in the fixed annual contribution after three years of service.

Effective October 1, 2022, the Retirement Savings Plan was amended to add a Roth elective deferral feature and to implement an automatic increase feature whereby a participant who contributes less than 10 percent will have their contribution percent increased by one percent annually unless the participant opts out.

Matching and fixed annual contributions to the Retirement Savings Plan are expensed as incurred and amounted to $21.9 million, $20.6 million and $17.9 million for fiscal years 2022, 2021 and 2020. At September 30, 2022 and 2021, the Retirement Savings Plan held 1.6 percent and 1.9 percent of our outstanding common stock.

11. Stock and Other Compensation Plans

Stock-Based Compensation Plans

Total stock-based compensation cost was $22.2 million, $24.1 million and $21.1 million for the fiscal years ended September 30, 2022, 2021 and 2020. Of this amount, $11.5 million, $12.9 million and $11.6 million was capitalized.

1998 Long-Term Incentive Plan

We have the 1998 Long-Term Incentive Plan (LTIP), which provides a comprehensive, long-term incentive compensation plan providing for discretionary awards of incentive stock options, non-qualified stock options, stock appreciation rights, bonus stock, time-lapse restricted stock, time-lapse restricted stock units, performance-based restricted stock units and stock units to certain employees and non-employee directors of the Company and our subsidiaries. The objectives of this plan include attracting and retaining the best available personnel, providing for additional performance incentives and promoting our success by providing employees with the opportunity to acquire common stock.

We are authorized to grant awards up to a maximum cumulative amount of 11.2 million shares of common stock under this plan subject to certain adjustment provisions. As of September 30, 2022, non-qualified stock options, bonus stock, time-lapse restricted stock, time-lapse restricted stock units, performance-based restricted stock units and stock units had been issued under this plan, and 0.9 million shares are available for future issuance.

Restricted Stock Units Award Grants

As noted above, the LTIP provides for discretionary awards of restricted stock units to help attract, retain and reward employees of Atmos Energy and its subsidiaries. Certain of these awards vest based upon the passage of time and other awards vest based upon the passage of time and the achievement of specified performance targets. The fair value of the awards granted is based on the market price of our stock at the date of grant. We estimate forfeitures using our historical forfeiture rate. The associated expense is recognized ratably over the vesting period. We use authorized and unissued shares to meet share requirements for the vesting of restricted stock units.

Employees who are granted time-lapse restricted stock units under our LTIP have a nonforfeitable right to dividend equivalents that are paid at the same rate and at the same time at which they are paid on shares of stock without restrictions. Time-lapse restricted stock units contain only a service condition that the employee recipients render continuous services to the Company for a period of three years from the date of grant, except for accelerated vesting in the event of death, disability, change of control of the Company or termination without cause (with certain exceptions). There are no performance conditions required to be met for employees to be vested in time-lapse restricted stock units.

Employees who are granted performance-based restricted stock units under our LTIP have a forfeitable right to dividend equivalents that accrue at the same rate at which they are paid on shares of stock without restrictions. Dividend equivalents on the performance-based restricted stock units are paid either in cash or in the form of shares upon the vesting of the award. Performance-based restricted stock units contain a service condition that the employee recipients render continuous services to the Company for a period of three years from the beginning of the applicable three-year performance period, except for accelerated vesting in the event of death, disability, change of control of the Company or termination without cause (with certain exceptions) and a performance condition based on a cumulative earnings per share target amount.

The following summarizes information regarding the restricted stock units granted under the plan during the fiscal years ended September 30, 2022, 2021 and 2020:

	2022		2021		2020	
	Number of Restricted Units	Weighted Average Grant-Date Fair Value	Number of Restricted Units	Weighted Average Grant-Date Fair Value	Number of Restricted Units	Weighted Average Grant-Date Fair Value
Nonvested at beginning of year	378,127	$ 102.45	443,279	$ 99.28	503,072	$ 91.66
Granted	179,738	108.07	223,954	102.68	199,985	102.34
Vested	(159,019)	100.99	(271,435)	97.44	(242,975)	85.66
Forfeited	(17,551)	103.37	(17,671)	101.48	(16,803)	96.87
Nonvested at end of year	381,295	$ 105.69	378,127	$ 102.45	443,279	$ 99.28

As of September 30, 2022, there was $14.1 million of total unrecognized compensation cost related to nonvested restricted stock units granted under the LTIP. That cost is expected to be recognized over a weighted average period of 1.4 years. The fair value of restricted stock vested during the fiscal years ended September 30, 2022, 2021 and 2020 was $16.0 million, $26.3 million and $20.7 million.

Other Plans

Direct Stock Purchase Plan

We maintain a Direct Stock Purchase Plan, open to all investors, which allows participants to have all or part of their cash dividends paid quarterly in additional shares of our common stock. The minimum initial investment required to join the plan is $1,250. Direct Stock Purchase Plan participants may purchase additional shares of our common stock as often as weekly with voluntary cash payments of at least $25, up to an annual maximum of $100,000.

Equity Incentive and Deferred Compensation Plan for Non-Employee Directors

We have an Equity Incentive and Deferred Compensation Plan for Non–Employee Directors, which provides non-employee directors of Atmos Energy with the opportunity to defer receipt, until retirement, of compensation for services rendered to the Company and invest deferred compensation into either a cash account or a stock account.

Other Discretionary Compensation Plans

We have an annual incentive program covering substantially all employees to give each employee an opportunity to share in our financial success based on the achievement of key performance measures considered critical to achieving business objectives for a given year with minimum and maximum thresholds. The Company must meet the minimum threshold for the plan to be funded and distributed to employees. These performance measures may include earnings growth objectives, improved cash flow objectives or crucial customer satisfaction and safety results. We monitor progress towards the achievement of the performance measures throughout the year and record accruals based upon the expected payout using the best estimates available at the time the accrual is recorded. During the last several fiscal years, we have used earnings per share as our sole performance measure.

12. Details of Selected Financial Statement Captions

The following tables provide additional information regarding the composition of certain financial statement captions.

Balance Sheet

Accounts receivable

Accounts receivable was comprised of the following at September 30, 2022 and 2021:

	September 30	
	2022	2021
	(In thousands)	
Billed accounts receivable	$ 258,333	$ 218,219
Unbilled revenue	121,518	97,417
Contributions in aid of construction receivable	5,390	18,984
Insurance receivable	13,160	53,779
Other accounts receivable	15,300	19,039
Total accounts receivable	413,701	407,438
Less: allowance for uncollectible accounts	(49,993)	(64,471)
Net accounts receivable	$ 363,708	$ 342,967

Other current assets

Other current assets as of September 30, 2022 and 2021 were comprised of the following accounts.

	September 30	
	2022	2021
	(In thousands)	
Deferred gas costs	$ 119,742	$ 66,395
Winter Storm Uri incremental costs	2,020,954	2,011,719
Prepaid expenses	58,551	48,766
Taxes receivable	11,911	—
Materials and supplies	25,880	15,581
Assets from risk management activities	26,207	55,073
Other	11,245	3,375
Total	$ 2,274,490	$ 2,200,909

Property, plant and equipment

Property, plant and equipment was comprised of the following as of September 30, 2022 and 2021:

	September 30	
	2022	2021
	(In thousands)	
Storage plant	$ 589,210	$ 539,972
Transmission plant	4,325,540	3,725,347
Distribution plant	13,511,409	12,085,654
General plant	937,500	868,962
Intangible plant	38,612	38,612
	19,402,271	17,258,547
Construction in progress	835,868	626,551
	20,238,139	17,885,098
Less: accumulated depreciation and amortization	(2,997,900)	(2,821,128)
Net property, plant and equipment (1)	$ 17,240,239	$ 15,063,970

(1) Net property, plant and equipment includes plant acquisition adjustments of $(26.6) million and $(28.5) million at September 30, 2022 and 2021.

Deferred charges and other assets

Deferred charges and other assets as of September 30, 2022 and 2021 were comprised of the following accounts.

	September 30	
	2022	2021
	(In thousands)	
Marketable securities	$ 96,012	$ 108,071
Regulatory assets (See Note 2)	368,375	351,843
Operating lease right of use assets (See Note 6)	214,663	222,446
Winter Storm Uri incremental costs	88,500	89,009
Assets from risk management activities	355,784	175,613
Pension assets	29,498	—
Other	20,968	27,738
Total	$ 1,173,800	$ 974,720

Accounts payable and accrued liabilities

Accounts payable and accrued liabilities as of September 30, 2022 and 2021 were comprised of the following accounts.

	September 30	
	2022	2021
	(In thousands)	
Trade accounts payable	$ 258,506	$ 224,873
Accrued gas payable	157,942	100,699
Accrued liabilities	79,571	97,650
Total	$ 496,019	$ 423,222

Other current liabilities

Other current liabilities as of September 30, 2022 and 2021 were comprised of the following accounts.

	September 30	
	2022	2021
	(In thousands)	
Customer credit balances and deposits	$ 56,016	$ 49,722
Accrued employee costs	47,661	50,517
Deferred gas costs	28,834	52,553
Operating lease liabilities (See Note 6)	38,644	37,688
Accrued interest	59,542	55,164
Liabilities from risk management activities	3,000	5,269
Taxes payable	189,239	160,986
Pension and postretirement liabilities	9,721	4,863
Regulatory cost of removal obligation	80,676	72,823
APT annual adjustment mechanism	18,034	22,694
Regulatory excess deferred taxes (See Note 14)	159,808	155,857
Other	28,982	18,545
Total	$ 720,157	$ 686,681

Deferred credits and other liabilities

Deferred credits and other liabilities as of September 30, 2022 and 2021 were comprised of the following accounts.

	September 30	
	2022	2021
	(In thousands)	
Pension and postretirement liabilities	$ 91,596	$ 185,617
Operating lease liabilities (See Note 6)	184,301	194,745
Customer advances for construction	8,628	9,879
Other regulatory liabilities (See Note 2)	178,990	75,506
Asset retirement obligation	5,737	18,373
Liabilities from risk management activities	1,129	—
APT annual adjustment mechanism	13,104	8,416
Unrecognized tax benefits (See Note 14)	39,908	32,792
Other	14,909	12,161
Total	$ 538,302	$ 537,489

Statement of Comprehensive Income

Other non-operating income (expense)

Other non-operating income (expense) for the fiscal years ended September 30, 2022, 2021 and 2020 were comprised of the following accounts.

	Year Ended September 30		
	2022	2021	2020
		(In thousands)	
Equity component of AFUDC	$ 45,505	$ 32,749	$ 23,493
Performance-based rate program	8,327	6,362	6,771
Pension and other postretirement non-service credit (cost)	8,337	(19,238)	(3,189)
Interest income	2,781	2,144	2,932
Community support spending	(16,357)	(14,460)	(11,728)
Unrealized losses on equity securities	(7,737)	(860)	(4,176)
Miscellaneous	(7,119)	(8,842)	(6,932)
Total	$ 33,737	$ (2,145)	$ 7,171

Statement of Cash Flows

Supplemental disclosures of cash flow information for the fiscal years ended September 30, 2022, 2021 and 2020 were as follows:

	Year Ended September 30		
	2022	2021	2020
		(In thousands)	
Cash Paid (Received) During The Period For:			
Interest [(1)]	$ 234,297	$ 207,555	$ 194,993
Income taxes	$ 15,760	$ 8,199	$ (3,071)
Non-Cash Transactions:			
Capital expenditures included in current liabilities	$ 217,868	$ 184,786	$ 113,365

(1) Cash paid during the period for interest, net of amounts capitalized was $98.4 million, $81.9 million and $82.3 million for the fiscal years ended September 30, 2022, 2021 and 2020.

13. Commitments and Contingencies

Litigation and Environmental Matters

In the normal course of business, we are subject to various legal and regulatory proceedings. For such matters, we record liabilities when they are considered probable and estimable, based on currently available facts, our historical experience and our estimates of the ultimate outcome or resolution of the liability in the future. While the outcome of these proceedings is uncertain and a loss in excess of the amount we have accrued is possible though not reasonably estimable, it is the opinion of management that any amounts exceeding the accruals will not have a material adverse impact on our financial position, results of operations or cash flows.

The National Transportation Safety Board (NTSB) held a public meeting on January 12, 2021 to determine the probable cause of the incident that occurred at a Dallas, Texas residence on February 23, 2018 that resulted in one fatality and injuries to four other residents. At the meeting, the Board deliberated and voted on proposed findings of fact, a probable cause statement, and safety recommendations. On February 8, 2021, the NTSB issued its final report that included an Executive Summary, Findings, Probable Cause and Recommendations. Also on February 8, 2021, safety recommendations letters were distributed to recommendation recipients, including Atmos Energy. Atmos Energy provided a written response on May 7, 2021. Following the release of the NTSB's final report, the Railroad Commission of Texas (RRC) completed its safety evaluation related to the same incident finding four alleged violations and initiated an enforcement proceeding to pursue administrative penalties totaling $1.6 million. Atmos Energy is working with the RRC to resolve the alleged violations and satisfy the administrative penalties.

On October 26, 2022, the NTSB issued its final report that included Factual Information, Analysis and Probable Cause of a worksite accident that occurred in Farmersville, Texas on June 28, 2021 that resulted in two fatalities and injuries to two others. Three civil actions have been filed in Dallas, Texas against Atmos Energy and one of its contractors in response to the accident.

We are a party to various other litigation and environmental-related matters or claims that have arisen in the ordinary course of our business. While the results of such litigation and response actions to such environmental-related matters or claims cannot be predicted with certainty, we continue to believe the final outcome of such litigation and matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Purchase Commitments

Our distribution divisions maintain supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of the individual contract.

Our Mid-Tex Division also maintains a limited number of long-term supply contracts to ensure a reliable source of gas for our customers in its service area, which obligate it to purchase specified volumes at prices under contracts indexed to natural gas trading hubs or fixed price contracts. At September 30, 2022, we were committed to purchase 55.6 Bcf within one year and 89.1 Bcf within two to three years under indexed contracts. At September 30, 2022, we were committed to purchase 13.2 Bcf within one year under fixed price contracts with a weighted average price of $5.39 per Mcf. Purchases under these contracts totaled $352.6 million, $149.4 million and $58.5 million for 2022, 2021 and 2020.

Rate Regulatory Proceedings

As of September 30, 2022, routine rate regulatory proceedings were in progress in some of our service areas, which are discussed in further detail above in the *Business — Ratemaking Activity* section.

14. Income Taxes

Income Tax Expense

The components of income tax expense from continuing operations for 2022, 2021 and 2020 were as follows:

	2022	2021	2020
		(In thousands)	
Current			
Federal	$ 2,849	$ —	$ —
State	28,125	252	14,193
Deferred			
Federal	43,435	128,867	143,039
State (1)	3,101	24,617	(11,879)
Income tax expense	$ 77,510	$ 153,736	$ 145,353

(1) Includes a non-cash income tax benefit of $21.0 million in fiscal 2020 resulting from the remeasurement of the rate at which state deferred taxes will reverse in the future as discussed below.

Reconciliations of the provision for income taxes computed at the statutory rate of 21 percent to the reported provisions for income taxes from continuing operations for 2022, 2021 and 2020 are set forth below:

	2022	2021	2020
		(In thousands)	
Tax at statutory rate	$ 178,901	$ 172,053	$ 156,827
Common stock dividends deductible for tax reporting	(1,355)	(1,372)	(1,419)
State taxes (net of federal benefit)	24,669	19,647	22,791
Amortization of excess deferred taxes	(127,193)	(45,382)	(16,125)
Remeasurement due to state deferred tax rate change	—	—	(20,962)
Other, net	2,488	8,790	4,241
Income tax expense	$ 77,510	$ 153,736	$ 145,353

Deferred income taxes reflect the tax effect of differences between the basis of assets and liabilities for book and tax purposes. The tax effect of temporary differences that gave rise to significant components of the deferred tax liabilities and deferred tax assets at September 30, 2022 and 2021 are presented below:

	2022	2021
	(In thousands)	
Deferred tax assets:		
Employee benefit plans	$ 57,094	$ 64,316
Net operating loss carryforwards	485,061	911,424
Charitable and other credit carryforwards	1,903	7,712
Regulatory excess deferred tax	110,548	148,200
Lease asset	50,007	52,138
Other	44,035	33,591
Total deferred tax assets	748,648	1,217,381
Valuation allowance	(523)	(663)
Net deferred tax assets	748,125	1,216,718
Deferred tax liabilities:		
Difference in net book value and net tax value of assets	(2,431,757)	(2,258,264)
Gas cost adjustments	(43,964)	(26,413)
Winter Storm Uri regulatory asset	(20,710)	(471,025)
Lease liability	(50,007)	(52,138)
Rate deferral adjustment	(49,309)	(47,445)
Interest rate agreements	(106,820)	(20,156)
Other	(45,063)	(47,086)
Total deferred tax liabilities	(2,747,630)	(2,922,527)
Net deferred tax liabilities	$ (1,999,505)	$ (1,705,809)

We deduct our purchased gas costs for federal income tax purposes in the period they are paid. As a result of impacts from Winter Storm Uri, we recorded a $471.0 million (tax effected) increase in our deferred tax liability and an increase in our net operating loss carryforward as of September 30, 2021. As a result of the financing order issued by the Texas RRC on February 8, 2022, we reduced the deferred tax liability associated with the Winter Storm Uri regulatory asset and the corresponding deferred tax asset associated with net operating loss carry forwards by $450.3 million during fiscal 2022.

At September 30, 2022, we had $441.3 million (tax effected) of federal net operating loss carryforwards. The federal net operating loss carryforwards are available to offset future taxable income and have no expiration date. The Company has no charitable contribution carryforwards to offset future taxable income as of September 30, 2022.

The Company also has $43.8 million (tax effected) of state net operating loss carryforwards (net of $11.4 million of federal effects) and $1.9 million of state tax credits carryforwards (net of $0.5 million of federal effects). Depending on the jurisdiction in which the state net operating loss was generated, the carryforwards expiration period begins in fiscal 2026.

At September 30, 2022, we had recorded liabilities associated with unrecognized tax benefits totaling $52.7 million, which includes $12.8 million in deferred tax liabilities. The following table reconciles the beginning and ending balance of our unrecognized tax benefits:

	2022	2021	2020
		(In thousands)	
Unrecognized tax benefits - beginning balance	$ 32,792	$ 30,921	$ 27,716
Increase (decrease) resulting from prior period tax positions	(721)	671	(26)
Increase resulting from current period tax positions	20,612	1,200	3,231
Unrecognized tax benefits - ending balance	52,683	32,792	30,921
Less: deferred federal and state income tax benefits	(11,063)	(6,886)	(6,493)
Total unrecognized tax benefits that, if recognized, would impact the effective income tax rate as of the end of the year	$ 41,620	$ 25,906	$ 24,428

The Company recognizes interest accrued related to unrecognized tax benefits in interest expense and penalties included within interest charges in our consolidated statements of comprehensive income. During the years ended September 30, 2022, 2021 and 2020, the Company recognized approximately $1.3 million, $1.4 million and $0.7 million in interest and penalties. The Company had approximately $11.7 million, $10.4 million and $8.2 million for the payment of interest and penalties accrued at September 30, 2022, 2021 and 2020.

We file income tax returns in the U.S. federal jurisdiction as well as in various states where we have operations. We have concluded substantially all U.S. federal income tax matters through fiscal year 2009 and concluded substantially all Texas income tax matters through fiscal year 2010.

Regulatory Excess Deferred Taxes

Regulatory excess net deferred taxes represent changes in our net deferred tax liability related to our cost of service ratemaking due to the enactment of the Tax Cuts and Jobs Act of 2017 (the TCJA) and a Kansas legislative change enacted in fiscal 2020. As of September 30, 2022 and 2021, $159.8 million and $155.9 million is recorded in other current liabilities.

Currently, the regulatory excess net deferred tax liability is being returned over various periods. Of this amount, $404.2 million, is being returned to customers over 35 - 60 months. An additional $78.4 million is being returned to customers on a provisional basis over 15 - 69 years until our regulators establish the final refund periods. The refund of the remaining $15.1 million will be addressed in future rate proceedings.

15. Financial Instruments

We currently use financial instruments to mitigate commodity price risk and interest rate risk. Our financial instruments do not contain any credit-risk-related or other contingent features that could cause accelerated payments when our financial instruments are in net liability positions.

Commodity Risk Management Activities

Our purchased gas cost adjustment mechanisms essentially insulate our distribution segment from commodity price risk; however, our customers are exposed to the effects of volatile natural gas prices. We manage this exposure through a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season.

In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Our distribution gas supply department is responsible for executing this segment’s commodity risk management activities in conformity with regulatory requirements. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2021-2022 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 42 percent, or approximately 23.9 Bcf of the winter flowing gas requirements at a weighted average cost of approximately $3.67 per Mcf. We have not designated these financial instruments as hedges for accounting purposes.

Interest Rate Risk Management Activities

We manage interest rate risk by periodically entering into financial instruments to effectively fix the Treasury yield component of the interest cost associated with anticipated financings.

The following table summarizes our existing forward starting interest rate swaps as of September 30, 2022. These swaps were designated as cash flow hedges at the time the agreements were executed.

Planned Debt Issuance Date	Amount Hedged
	(In thousands)
Fiscal 2024	$ 450,000
Fiscal 2025	600,000
Fiscal 2026	300,000
	$ 1,350,000

Quantitative Disclosures Related to Financial Instruments

The following tables present detailed information concerning the impact of financial instruments on our consolidated balance sheet and statements of comprehensive income.

As of September 30, 2022, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of September 30, 2022, we had 14,335 MMcf of net long commodity contracts outstanding. These contracts have not been designated as hedges.

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments as of September 30, 2022 and 2021. As discussed in Note 2 to the consolidated financial statements, we report our financial instruments as risk management assets and liabilities, each of which is classified as current or noncurrent based upon the anticipated settlement date of the underlying financial instrument. The gross amounts of recognized assets and liabilities are netted within our consolidated balance sheets to the extent that we have netting arrangements with the counterparties. However, as of September 30, 2022 and 2021, no gross amounts and no cash collateral were netted within our consolidated balance sheet.

	Balance Sheet Location	Assets	Liabilities
		(In thousands)	
September 30, 2022			
Designated As Hedges:			
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	$ 355,075	$ —
Total		355,075	—
Not Designated As Hedges:			
Commodity contracts	Other current assets / Other current liabilities	26,207	(3,000)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	709	(1,129)
Total		26,916	(4,129)
Gross / Net Financial Instruments		$ 381,991	$ (4,129)

	Balance Sheet Location	Assets	Liabilities
		(In thousands)	
September 30, 2021			
Designated As Hedges:			
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	$ 169,469	$ —
Total		169,469	—
Not Designated As Hedges:			
Commodity contracts	Other current assets / Other current liabilities	55,073	(5,269)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	6,144	—
Total		61,217	(5,269)
Gross / Net Financial Instruments		$ 230,686	$ (5,269)

Impact of Financial Instruments on the Statement of Comprehensive Income

Cash Flow Hedges

As discussed above, our distribution segment has interest rate agreements, which we designate as cash flow hedges at the time the agreements were executed. The net loss on settled interest rate agreements reclassified from AOCI into interest charges on our consolidated statements of comprehensive income for the years ended September 30, 2022, 2021 and 2020 was $3.8 million, $5.9 million and $5.5 million.

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income, net of taxes, for the years ended September 30, 2022 and 2021.

	Fiscal Year Ended September 30	
	2022	2021
	(In thousands)	
Increase in fair value:		
Interest rate agreements	$ 296,875	$ 123,017
Recognition of losses in earnings due to settlements:		
Interest rate agreements	2,976	4,566
Total other comprehensive income from hedging, net of tax	$ 299,851	$ 127,583

Deferred gains (losses) recorded in AOCI associated with our interest rate agreements are recognized in earnings as they are amortized over the terms of the underlying debt instruments. As of September 30, 2022, we had $94.1 million of net realized gains in AOCI associated with our interest rate agreements. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred net gains recorded in AOCI associated with our interest rate agreements, based upon the fair values of these agreements at the date of settlement. The remaining amortization periods for these settled amounts extend through fiscal 2053. However, the table below does not include the expected recognition in earnings of our outstanding interest rate agreements as those financial instruments have not yet settled.

		Interest Rate Agreements
		(In thousands)
2023	$	2,120
2024		2,120
2025		2,120
2026		2,120
2027		2,120
Thereafter		83,547
Total	$	94,147

Financial Instruments Not Designated as Hedges

As discussed above, commodity contracts which are used in our distribution segment are not designated as hedges. However, there is no earnings impact on our distribution segment as a result of the use of these financial instruments because the gains and losses arising from the use of these financial instruments are recognized in the consolidated statements of comprehensive income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue. Accordingly, the impact of these financial instruments is excluded from this presentation.

16. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2 to the consolidated financial statements.

Fair value measurements also apply to the valuation of our pension and postretirement plan assets. The fair value of these assets is presented in Note 10 to the consolidated financial statements.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2022 and 2021. As required under authoritative accounting literature, assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)(1)	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral	September 30, 2022
			(In thousands)		
Assets:					
Financial instruments	$ —	$ 381,991	$ —	$ —	$ 381,991
Debt and equity securities					
Registered investment companies	26,367	—	—	—	26,367
Bond mutual funds	32,367	—	—	—	32,367
Bonds (2)	—	33,433	—	—	33,433
Money market funds	—	3,845	—	—	3,845
Total debt and equity securities	58,734	37,278	—	—	96,012
Total assets	$ 58,734	$ 419,269	$ —	$ —	$ 478,003
Liabilities:					
Financial instruments	$ —	$ 4,129	$ —	$ —	$ 4,129

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)(1)	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral	September 30, 2021
			(In thousands)		
Assets:					
Financial instruments	$ —	$ 230,686	$ —	$ —	$ 230,686
Debt and equity securities					
Registered investment companies	35,175	—	—	—	35,175
Bond mutual funds	34,298	—	—	—	34,298
Bonds (2)	—	35,655	—	—	35,655
Money market funds	—	2,943	—	—	2,943
Total debt and equity securities	69,473	38,598	—	—	108,071
Total assets	$ 69,473	$ 269,284	$ —	$ —	$ 338,757
Liabilities:					
Financial instruments	$ —	$ 5,269	$ —	$ —	$ 5,269

(1) Our Level 2 measurements consist of over-the-counter options and swaps, which are valued using a market-based approach in which observable market prices are adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences, municipal and corporate bonds, which are valued based on the most recent available quoted market prices and money market funds which are valued at cost.

(2) Our investments in bonds are considered available-for-sale debt securities in accordance with current accounting guidance.

Debt and equity securities are comprised of our available-for-sale debt securities and our equity securities. We evaluate the performance of our available-for-sale debt securities on an investment by investment basis for impairment, taking into consideration the investment's purpose, volatility, current returns and any intent to sell the security. As of September 30, 2022, no allowance for credit losses was recorded for our available-for-sale debt securities. At September 30, 2022 and 2021, the amortized cost of our available-for-sale debt securities was $34.1 million and $35.6 million. At September 30, 2022 we maintained investments in bonds that have contractual maturity dates ranging from October 2022 through September 2026.

Other Fair Value Measures

In addition to the financial instruments above, we have several financial and nonfinancial assets and liabilities subject to fair value measures. These financial assets and liabilities include cash and cash equivalents, accounts receivable, accounts payable, finance leases and debt, which are recorded at carrying value. The nonfinancial assets and liabilities include asset retirement obligations and pension and postretirement plan assets. For cash and cash equivalents, accounts receivable, accounts payable and finance leases we consider carrying value to materially approximate fair value due to the short-term nature of these assets and liabilities.

Our long-term debt is recorded at carrying value. The fair value of our long-term debt, excluding finance leases, is determined using third party market value quotations, which are considered Level 1 fair value measurements for debt instruments with a recent, observable trade or Level 2 fair value measurements for debt instruments where fair value is determined using the most recent available quoted market price. The following table presents the carrying value and fair value of our long-term debt, excluding finances leases, debt issuance costs and original issue premium or discount, as of September 30, 2022:

	September 30, 2022
	(In thousands)
Carrying Amount	$ 7,960,000
Fair Value	$ 6,918,843

17. Concentration of Credit Risk

Credit risk is the risk of financial loss to us if a customer fails to perform its contractual obligations. We engage in transactions for the purchase and sale of products and services with major companies in the energy industry and with industrial, commercial, residential and municipal energy consumers. These transactions principally occur in the southern and midwestern regions of the United States. We believe that this geographic concentration does not contribute significantly to our overall exposure to credit risk. Credit risk associated with trade accounts receivable for the distribution segment is mitigated by the large number of individual customers and the diversity in our customer base. The credit risk for our pipeline and storage segment is not significant.

ITEM 9. ***Changes in and Disagreements With Accountants on Accounting and Financial Disclosure.***

None.

ITEM 9A. ***Controls and Procedures.***

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of September 30, 2022 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f), in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we evaluated the effectiveness of our internal control over financial reporting based on the framework in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (COSO). Based on our evaluation under the framework in *Internal Control-Integrated Framework* issued by COSO and applicable Securities and Exchange Commission rules, our management concluded that our internal control over financial reporting was effective as of September 30, 2022, in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Ernst & Young LLP has issued its report on the effectiveness of the Company's internal control over financial reporting. That report appears below.

/s/ JOHN K. AKERS	/s/ CHRISTOPHER T. FORSYTHE
John K. Akers	Christopher T. Forsythe
President, Chief Executive Officer and Director	Senior Vice President and Chief Financial Officer

November 14, 2022

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Atmos Energy Corporation

Opinion on Internal Control Over Financial Reporting

We have audited Atmos Energy Corporation's internal control over financial reporting as of September 30, 2022, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Atmos Energy Corporation (the Company) maintained, in all material respects, effective internal control over financial reporting as of September 30, 2022, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the 2022 consolidated financial statements of the Company and our report dated November 14, 2022 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Ernst & Young LLP

Dallas, Texas
November 14, 2022

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Act) during the fourth quarter of the fiscal year ended September 30, 2022 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. *Other Information.*

Not applicable.

PART III

ITEM 10. *Directors, Executive Officers and Corporate Governance.*

Information regarding directors is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 8, 2023. Information regarding executive officers is reported below:

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

The following table sets forth certain information as of September 30, 2022, regarding the executive officers of the Company. It is followed by a brief description of the business experience of each executive officer.

Name	Age	Years of Service	Office Currently Held
John K. Akers	59	31	President, Chief Executive Officer and Director
Christopher T. Forsythe	51	19	Senior Vice President and Chief Financial Officer
John S. McDill	58	35	Senior Vice President, Utility Operations
Karen E. Hartsfield	52	7	Senior Vice President, General Counsel and Corporate Secretary
John M. Robbins	52	9	Senior Vice President, Human Resources

John K. (Kevin) Akers was named President and Chief Executive Officer and was appointed to the Board of Directors effective October 1, 2019. Mr. Akers joined the company in 1991. Mr. Akers assumed increased responsibilities over time and was named President of the Mississippi Division in 2002. He was later named President of the Kentucky/Mid-States Division in May 2007, a position he held until December 2016. Effective January 1, 2017, Mr. Akers was named Senior Vice President, Safety and Enterprise Services and was responsible for customer service, facilities management, safety and supply chain management. In November 2018, Mr. Akers was named Executive Vice President and assumed oversight responsibility for APT.

Christopher T. Forsythe was named Senior Vice President and Chief Financial Officer effective February 1, 2017. Mr. Forsythe joined the Company in June 2003 and prior to this promotion, served as the Company's Vice President and Controller from May 2009 through January 2017. Prior to joining Atmos Energy, Mr. Forsythe worked in public accounting for 10 years.

John S. McDill was named Senior Vice President, Utility Operations, effective October 1, 2021. In this role, Mr. McDill is responsible for the operations of Atmos Energy's six utility divisions as well as gas supply. Prior to this promotion, Mr. McDill served as Vice President, Pipeline Safety from May 2012 to September 2021. Mr. McDill also served as Vice President of Operations in our Mississippi Division. Mr. McDill's years of service include that with Mississippi Valley Gas, a company acquired by Atmos Energy in 2002.

Karen E. Hartsfield was named Senior Vice President, General Counsel and Corporate Secretary of Atmos Energy, effective August 7, 2017. Ms. Hartsfield joined the Company in June 2015, after having served in private practice for 19 years, most recently as Managing Partner of Jackson Lewis LLP in its Dallas office from July 2013 to June 2015. Prior to joining Jackson Lewis as a partner in January 2009, Ms. Hartsfield was a partner with Baker Botts LLP in Dallas.

John M. (Matt) Robbins was named Senior Vice President, Human Resources, effective January 1, 2017. Mr. Robbins joined the Company in May 2013 and prior to this promotion served as Vice President, Human Resources from February 2015 to December 2016. Before joining Atmos Energy, Mr. Robbins had over 20 years of experience in human resources.

Identification of the members of the Audit Committee of the Board of Directors as well as the Board of Directors' determination as to whether one or more audit committee financial experts are serving on the Audit Committee of the Board of

Directors is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 8, 2023.

The Company has adopted a code of ethics for its principal executive officer, principal financial officer and principal accounting officer. Such code of ethics is represented by the Company's Code of Conduct, which is applicable to all directors, officers and employees of the Company, including the Company's principal executive officer, principal financial officer and principal accounting officer. A copy of the Company's Code of Conduct, as well as any amendment to or waiver granted from a provision of the Company's Code of Conduct is posted on the Company's website at *www.atmosenergy.com/company/corporate-responsibility-reports*.

ITEM 11. *Executive Compensation.*

Information on executive compensation is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 8, 2023, under the captions "Director Compensation," "Compensation Discussion and Analysis," "Other Executive Compensation Matters" and "Named Executive Officer Compensation."

ITEM 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.*

Security ownership of certain beneficial owners and of management is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 8, 2023, under the heading "Beneficial Ownership of Common Stock." Information concerning our equity compensation plans is provided in Part II, Item 5, "Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities", of this Annual Report on Form 10-K.

ITEM 13. *Certain Relationships and Related Transactions, and Director Independence.*

Information on certain relationships and related transactions as well as director independence is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 8, 2023, under the heading "Corporate Governance and Other Board Matters," and "Proposal One – Election of Directors."

ITEM 14. *Principal Accountant Fees and Services.*

Information on our principal accountant's fees and services is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 8, 2023, under the heading "Proposal Two – Ratification of Appointment of Independent Registered Public Accounting Firm."

PART IV

ITEM 15. *Exhibits and Financial Statement Schedules.*

(a) 1. and 2. *Financial statements and financial statement schedules.*

The financial statements listed in the Index to Financial Statements in Part II, Item 8 are filed as part of this Form 10-K. All financial statement schedules are omitted because the required information is not present, or not present in amounts sufficient to require submission of the schedule or because the information required is included in the financial statements and accompanying notes thereto.

3. *Exhibits*

Exhibit Number	Description	Page Number or Incorporation by Reference to
	Articles of Incorporation and Bylaws	
3.1	Restated Articles of Incorporation of Atmos Energy Corporation - Texas (As Amended Effective February 3, 2010)	Exhibit 3.1 to Form 10-Q dated March 31, 2010 (File No. 1-10042)
3.2	Restated Articles of Incorporation of Atmos Energy Corporation - Virginia (As Amended Effective February 3, 2010)	Exhibit 3.2 to Form 10-Q dated March 31, 2010 (File No. 1-10042)

3.3	Amended and Restated Bylaws of Atmos Energy Corporation (as of February 5, 2019)	Exhibit 3.1 to Form 8-K dated February 5, 2019 (File No. 1-10042)
	Instruments Defining Rights of Security Holders, Including Indentures	
4.1(a)	Specimen Common Stock Certificate (Atmos Energy Corporation)	Exhibit 4.1 to Form 10-K for fiscal year ended September 30, 2012 (File No. 1-10042)
4.1(b)	Description of Registrant's Securities	Exhibit 4.1(b) to Form 10-K for fiscal year ended September 30, 2021 (File No. 1-10042)
4.2	Indenture dated as of November 15, 1995 between United Cities Gas Company and Bank of America Illinois, Trustee	Exhibit 4.11(a) to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.3	Indenture dated as of July 15, 1998 between Atmos Energy Corporation and U.S. Bank Trust National Association, Trustee	Exhibit 4.8 to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.4	Indenture dated as of May 22, 2001 between Atmos Energy Corporation and SunTrust Bank, Trustee	Exhibit 99.3 to Form 8-K dated May 22, 2001 (File No. 1-10042)
4.5	Indenture dated as of March 26, 2009 between Atmos Energy Corporation and U.S. Bank National Corporation, Trustee	Exhibit 4.1 to Form 8-K dated March 26, 2009 (File No. 1-10042)
4.6(a)	Debenture Certificate for the 6 3/4% Debentures due 2028	Exhibit 99.2 to Form 8-K dated July 29, 1998 (File No. 1-10042)
4.6(b)	Global Security for the 5.95% Senior Notes due 2034	Exhibit 10(2)(g) to Form 10-K for fiscal year ended September 30, 2004 (File No. 1-10042)
4.6(c)	Officers' Certificate dated June 10, 2011	Exhibit 4.1 to Form 8-K dated June 13, 2011 (File No. 1-10042)
4.6(d)	Global Security for the 5.5% Senior Notes due 2041	Exhibit 4.2 to Form 8-K dated June 13, 2011 (File No. 1-10042)
4.6(e)	Officers' Certificate dated January 11, 2013	Exhibit 4.1 to Form 8-K dated January 15, 2013 (File No. 1-10042)
4.6(f)	Global Security for the 4.15% Senior Notes due 2043	Exhibit 4.2 to Form 8-K dated January 15, 2013 (File No. 1-10042)
4.6(g)	Officers' Certificate dated October 15, 2014	Exhibit 4.1 to Form 8-K dated October 17, 2014 (File No. 1-10042)
4.6(h)	Global Security for the 4.125% Senior Notes due 2044	Exhibit 4.2 to Form 8-K dated October 17, 2014 (File No. 1-10042)
4.6(i)	Officers' Certificate dated June 8, 2017	Exhibit 4.1 to Form 8-K dated June 8, 2017 (File No. 1-10042)
4.6(j)	Officers' Certificate dated October 4, 2018	Exhibit 4.1 to Form 8-K dated October 4, 2018 (File No. 1-10042)
4.6(k)	Global Security for the 4.300% Senior Notes due 2048	Exhibit 4.2 to Form 8-K dated October 4, 2018 (File No. 1-10042)
4.6(l)	Global Security for the 4.300% Senior Notes due 2048	Exhibit 4.3 to Form 8-K dated October 4, 2018 (File No. 1-10042)
4.6(m)	Officers' Certificate dated March 4, 2019	Exhibit 4.1 to Form 8-K dated March 4, 2019 (File No. 1-10042)
4.6(n)	Global Security for the 4.125% Senior Notes due 2049	Exhibit 4.2 to Form 8-K dated March 4, 2019 (File No. 1-10042)
4.6(o)	Officers' Certificate dated October 2, 2019	Exhibit 4.1 to Form 8-K dated October 2, 2019 (File No. 1-10042)

4.6(p)	Global Security for the 2.625% Senior Notes due 2029	Exhibit 4.2 to Form 8-K dated October 2, 2019 (File No. 1-10042)
4.6(q)	Global Security for the 3.375% Senior Notes due 2049	Exhibit 4.3 to Form 8-K dated October 2, 2019 (File No. 1-10042)
4.6(r)	Officers' Certificate dated October 1, 2020	Exhibit 4.1 to Form 8-K dated October 1, 2020 (File No. 1-10042)
4.6(s)	Global Security for the 1.500% Senior Notes due 2031	Exhibit 4.2 to Form 8-K dated October 1, 2020 (File No. 1-10042)
4.6(t)	Global Security for the 1.500% Senior Notes due 2031	Exhibit 4.3 to Form 8-K dated October 1, 2020 (File No. 1-10042)
4.6(u)	Fixed Rate Notes Officers' Certificate dated March 9, 2021	Exhibit 4.1 to Form 8-K dated March 9, 2021 (File No. 1-10042)
4.6(v)	Floating Rate Notes Officers' Certificate dated March 9, 2021	Exhibit 4.2 to Form 8-K dated March 9, 2021 (File No. 1-10042)
4.6(w)	Global Security for the 0.625% Senior Notes due 2023	Exhibit 4.3 to Form 8-K dated March 9, 2021 (File No. 1-10042)
4.6(x)	Global Security for the 0.625% Senior Notes due 2023	Exhibit 4.4 to Form 8-K dated March 9, 2021 (File No. 1-10042)
4.6(y)	Global Security for the 0.625% Senior Notes due 2023	Exhibit 4.5 to Form 8-K dated March 9, 2021 (File No. 1-10042)
4.6(z)	Global Security for the Floating Rate Senior Notes due 2023	Exhibit 4.6 to Form 8-K dated March 9, 2021 (File No. 1-10042)
4.6(aa)	Global Security for the Floating Rate Senior Notes due 2023	Exhibit 4.7 to Form 8-K dated March 9, 2021 (File No. 1-10042)
4.6(bb)	Global Security for the Floating Rate Senior Notes due 2023	Exhibit 4.8 to Form 8-K dated March 9, 2021 (File No. 1-10042)
4.6(cc)	Officers' Certificate dated October 1, 2021	Exhibit 4.1 to Form 8-K dated October 1, 2021 (File No. 1-10042)
4.6(dd)	Global Security for the 2.850% Senior Notes due 2052	Exhibit 4.2 to Form 8-K dated October 1, 2021 (File No. 1-10042)
4.6(ee)	Global Security for the 2.850% Senior Notes due 2052	Exhibit 4.3 to Form 8-K dated October 1, 2021 (File No. 1-10042)
4.6(ff)	Officers' Certificate dated January 14, 2022	Exhibit 4.1 to Form 8-K dated January 14, 2022 (File No. 1-10042)
4.6(gg)	Global Security for the 2.625% Senior Notes due 2029	Exhibit 4.2 to Form 8-K dated January 14, 2022 (File No. 1-10042)
4.6(hh)	Officers' Certificate dated October 3, 2022	Exhibit 4.1 to Form 8-K dated October 3, 2022 (File No. 1-10042)
4.6(ii)	Global Security for the 5.450% Senior Notes due 2032	Exhibit 4.2 to Form 8-K dated October 3, 2022 (File No. 1-10042)
4.6(jj)	Global Security for the 5.750% Senior Notes due 2052	Exhibit 4.3 to Form 8-K dated October 3, 2022 (File No. 1-10042)
	Material Contracts	
10.1(a)	Revolving Credit Agreement, dated as of March 31, 2021, among Atmos Energy Corporation, Crédit Agricole Corporate and Investment Bank, as the Administrative Agent, the agents, arrangers and bookrunners named therein, and the lenders named therein	Exhibit 10.1 to Form 8-K dated March 31, 2021 (File No. 1-10042)

10.1(b)	First Amendment to Revolving Credit Agreement, dated as of March 31, 2022, among Atmos Energy Corporation, Credit Agricole Corporate and Investment Bank, as the Administrative Agent, the agents, arrangers and bookrunners named therein, and the lenders named therein	Exhibit 10.2 to Form 8-K dated April 1, 2022 (File No. 1-10042)
10.2(a)	Revolving Credit Agreement, dated as of March 31, 2021, among Atmos Energy Corporation, Crédit Agricole Corporate and Investment Bank, as the Administrative Agent, the agents, arrangers and bookrunners named therein, and the lenders named therein	Exhibit 10.2 to Form 8-K dated March 31, 2021 (File No. 1-10042)
10.2(b)	First Amendment to Revolving Credit Agreement, dated as of March 31, 2022, among Atmos Energy Corporation, Credit Agricole Corporate and Investment Bank, as the Administrative Agent, the agents, arrangers and bookrunners named therein, and the lenders named therein	Exhibit 10.1 to Form 8-K dated April 1, 2022 (File No. 1-10042)
10.3(a)	Equity Distribution Agreement, dated as of February 12, 2020, among Atmos Energy Corporation and the Managers and Forward Purchasers named in Schedule A thereto	Exhibit 1.1 to Form 8-K dated February 12, 2020 (File No. 1-10042)
10.3(b)	Form of Master Forward Sale Confirmation	Exhibit 1.2 to Form 8-K dated February 12, 2020 (File No. 1-10042)
10.4(a)	Equity Distribution Agreement, dated as of June 29, 2021, among Atmos Energy Corporation and the Managers and Forward Purchasers named in Schedule A thereto	Exhibit 1.1 to Form 8-K dated June 29, 2021 (File No. 1-10042)
10.4(b)	Form of Master Forward Sale Confirmation	Exhibit 1.2 to Form 8-K dated June 29, 2021 (File No. 1-10042)
10.5(a)	Equity Distribution Agreement, dated as of March 23, 2022, among Atmos Energy Corporation and the Managers and Forward Purchases named in Schedule A thereto	Exhibit 1.1 to Form 8-K dated March 23, 2022 (File No. 1-10042)
10.5(b)	Form of Master Forward Sale Confirmation	Exhibit 1.2 to Form 8-K dated March 23, 2022 (File No. 1-10042)
	Executive Compensation Plans and Arrangements	
10.6(a)*	Form of Atmos Energy Corporation Change in Control Severance Agreement - Tier I	Exhibit 10.7(a) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.6(b)*	Form of Atmos Energy Corporation Change in Control Severance Agreement - Tier II	Exhibit 10.7(b) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.7(a)*	Atmos Energy Corporation Executive Retiree Life Plan	Exhibit 10.31 to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.7(b)*	Amendment No. 1 to the Atmos Energy Corporation Executive Retiree Life Plan	Exhibit 10.31(a) to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.8*	Atmos Energy Corporation Annual Incentive Plan for Management (as amended and restated August 3, 2021)	Exhibit 10.1 to Form 8-K dated August 3, 2021 (File No. 1-10042)
10.9(a)*	Atmos Energy Corporation Supplemental Executive Benefits Plan, Amended and Restated in its Entirety August 7, 2007	Exhibit 10.8(a) to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)

10.9(b)*	Form of Individual Trust Agreement for the Supplemental Executive Benefits Plan	Exhibit 10.3 to Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042)
10.10(a)*	Atmos Energy Corporation Supplemental Executive Retirement Plan (As Amended and Restated, Effective as of January 1, 2016)	Exhibit 10.7(a) to Form 10-K for fiscal year ended September 30, 2016 (File No. 1-10042)
10.10(b)*	Atmos Energy Corporation Performance-Based Supplemental Executive Benefits Plan Trust Agreement, Effective Date December 1, 2000	Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042)
10.11*	Atmos Energy Corporation Account Balance Supplemental Executive Retirement Plan (As Amended and Restated, Effective as of January 1, 2022)	Exhibit 10.1 to Form 10-Q dated December 31, 2021 (File No. 1-10042)
10.12(a)*	Mini-Med/Dental Benefit Extension Agreement dated October 1, 1994	Exhibit 10.28(f) to Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042)
10.12(b)*	Amendment No. 1 to Mini-Med/Dental Benefit Extension Agreement dated August 14, 2001	Exhibit 10.28(g) to Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042)
10.12(c)*	Amendment No. 2 to Mini-Med/Dental Benefit Extension Agreement dated December 31, 2002	Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2002 (File No. 1-10042)
10.13*	Atmos Energy Corporation Equity Incentive and Deferred Compensation Plan for Non-Employee Directors, Amended and Restated as of January 1, 2012	Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2011 (File No. 1-10042)
10.14(a)*	Atmos Energy Corporation 1998 Long-Term Incentive Plan (as amended and restated February 3, 2021)	
10.14(b)*	Form of Award Agreement of Time-Lapse Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 10.13(b) to Form 10-K for fiscal year ended September 20, 2020 (File No. 1-10042)
10.14(c)*	Form of Award Agreement of Performance-Based Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 10.13(c) to Form 10-K for fiscal year ended September 20, 2020 (File No. 1-10042)
10.14(d)*	Form of Non-Employee Director Award Agreement of Time-Lapse Restricted Stock Units Under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 10.11(d) to Form 10-K for fiscal year ended September 30, 2019 (File No. 1-10042)
10.14(e)*	Form of Non-Employee Director Award Agreement of Stock Unit Awards Under The Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 10.11(e) to Form 10-K for fiscal year ended September 30, 2019 (File No. 1-10042)
	Other Exhibits, as indicated	
21	Subsidiaries of the registrant	
23.1	Consent of independent registered public accounting firm, Ernst & Young LLP	
24	Power of Attorney	Signature page of Form 10-K for fiscal year ended September 30, 2022
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications**	
	Interactive Data File	
101.INS	XBRL Instance Document - the Instance Document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document	
101.SCH	Inline XBRL Taxonomy Extension Schema	
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase	
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase	

101.LAB	Inline XBRL Taxonomy Extension Labels Linkbase
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase
104	Cover Page Interactive Data File - the cover page interactive data file does not appear in the interactive data file because its XBRL tags are embedded within the Inline XBRL document

* This exhibit constitutes a "management contract or compensatory plan, contract, or arrangement."

** These certifications pursuant to 18 U.S.C. Section 1350 by the Company's Chief Executive Officer and Chief Financial Officer, furnished as Exhibit 32 to this Annual Report on Form 10-K, will not be deemed to be filed with the Securities and Exchange Commission or incorporated by reference into any filing by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates such certifications by reference.

ITEM 16. ***Form 10-K Summary.***

Not applicable.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ CHRISTOPHER T. FORSYTHE

Christopher T. Forsythe
Senior Vice President and
Chief Financial Officer

Date: November 14, 2022

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below hereby constitutes and appoints John K. Akers and Christopher T. Forsythe, or either of them acting alone or together, as his true and lawful attorney-in-fact and agent with full power to act alone, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ KIM R. COCKLIN Kim R. Cocklin	Chairman of the Board	November 14, 2022
/s/ JOHN K. AKERS John K. Akers	President, Chief Executive Officer and Director	November 14, 2022
/s/ CHRISTOPHER T. FORSYTHE Christopher T. Forsythe	Senior Vice President and Chief Financial Officer	November 14, 2022
/s/ RICHARD M. THOMAS Richard M. Thomas	Vice President and Controller (Principal Accounting Officer)	November 14, 2022
/s/ JOHN C. ALE John C. Ale	Director	November 14, 2022
/s/ KELLY H. COMPTON Kelly H. Compton	Director	November 14, 2022
/s/ SEAN DONOHUE Sean Donohue	Director	November 14, 2022
/s/ RAFAEL G. GARZA Rafael G. Garza	Director	November 14, 2022
/s/ RICHARD K. GORDON Richard K. Gordon	Director	November 14, 2022
/s/ NANCY K. QUINN Nancy K. Quinn	Director	November 14, 2022
/s/ RICHARD A. SAMPSON Richard A. Sampson	Director	November 14, 2022
/s/ DIANA J. WALTERS Diana J. Walters	Director	November 14, 2022
/s/ FRANK YOHO Frank Yoho	Director	November 14, 2022